NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

March 31, 2011

VIA ELECTRONIC FILING
Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: *North American Electric Reliability Corporation,*
Docket No*. RM06-16-000*

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC") regulations seeking approval of the following proposed Protection and Control ("PRC") standard and Emergency Preparedness and Operations ("EOP") standard set forth as **Exhibit A** to this petition that were approved by the NERC Board of Trustees on November 4, 2010.

- PRC-006-1 – Automatic Underfrequency Load Shedding
- EOP-003-2 – Load Shedding Plans

In developing the standards proposed in this filing, the standard drafting team also addressed some of FERC's directives in Order No. 693.[1] In doing so, the standard drafting team determined that it was necessary to retire several FERC-approved Reliability Standards to prevent duplication in the new standards being proposed in this

[1] *See Mandatory Reliability Standards for the Bulk-Power System*, 18 CFR Part 40, Docket No. RM06-16-000 (March 16, 2007) ("Order No. 693") at PP 627-630, 636-638.

filing. Accordingly, as explained below, the Implementation Plans for the new EOP and PRC Reliability Standards recommend retirement of the following standards when PRC-006-1 and EOP-003-2 become effective:

- PRC-006-0 – Development and Documentation of Regional UFLS Programs
- PRC-007-0 – Assuring Consistency of Entity Underfrequency Load Shedding Programs
- PRC-009-0 – Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event
- EOP-003-1 – Load Shedding Plans

This filing discusses each of the new standards (PRC-006-1 and EOP-003-2), including how the standards meet the criteria identified by FERC in Order No. 672[2] for approving Reliability Standards, and the basis for the retirement of the other listed standards.

This filing consists of the following:

- This transmittal letter;
- A table of contents;
- A narrative description explaining how the proposed Reliability Standards meet FERC's requirements;
- Reliability Standards submitted for approval (**Exhibit A**);
- Implementation Plans submitted for approval (**Exhibit B**);
- Mapping of Existing Requirements to New Requirements (**Exhibit C**);
- Consideration of Comments Document (**Exhibit D**);
- Standard Drafting Team Roster (**Exhibit E**); and,
- Development Record of the proposed Reliability Standards (**Exhibit F**)

Please contact me if you have any questions regarding this filing.

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[2] *See Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, FERC Stats. & Regs.*, ¶ 31,204 at PP 320-338 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").

Respectfully submitted,

/s/ Holly A. Hawkins
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**) Docket No. RM__-__-000)**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED NEW RELIABILITY STANDARDS AND IMPLEMENTATION PLANS RELATED TO UNDER-FREQUENCY LOAD-SHEDDING

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby requests the Federal Energy Regulatory Commission ("FERC") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of FERC's regulations, 18 C.F.R. § 39.5 the following Reliability Standards:

- PRC-006-1 – Automatic Underfrequency Load Shedding
- EOP-003-2 – Load Shedding Plans

Additionally, NERC requests FERC approval for implementation plans that call for the retirement of the following standards, pending the approval of PRC-006-1 and EOP-003-2:

- PRC-006-0 – Development and Documentation of Regional UFLS Programs
- PRC-007-0 – Assuring Consistency of Entity Underfrequency Load Shedding Programs
- PRC-009-0 – Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event
- EOP-003-1 – Load Shedding Plans

The NERC Board of Trustees approved the proposed Reliability Standards and Implementation Plans on November 4, 2010. In this filing, NERC requests that FERC approve the proposed Reliability Standards and make them effective in accordance with the implementation plan accompanying this filing. NERC also requests that FERC apply existing and FERC-approved Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") to the modified requirements proposed in this filing.

[1] NERC has been certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order).
[2] 16 U.S.C. 824o.

Exhibit A to this filing sets forth the proposed Reliability Standards. **Exhibit B** includes the Implementation Plan proposed for approval. **Exhibit C** presents the mapping of the existing requirements to new requirements. **Exhibit D** presents the Consideration of Comments Documents. **Exhibit E** presents the roster for the drafting team that developed the proposed Reliability Standards. And **Exhibit F** contains the complete development record of the proposed Reliability Standards. NERC is also filing these proposed Reliability Standards and implementation plans with applicable governmental authorities in Canada.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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*Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of the Commission's rules to permit the inclusion of more than two people on the service list.

III. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[3] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. Section 215 states that all users, owners and operators of the bulk power system in the United States will be subject to the FERC-approved Reliability Standards.

The principal purpose of the proposed Reliability Standard, PRC-006-1 – Automatic Underfrequency Load Shedding, is to establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs which arrest declining frequency, and assist recovery of frequency following system events leading to frequency degradation. UFLS programs provide automated system preservation measures in such events. EOP-003-2 – Load Shedding Plans was revised to eliminate duplicative requirements pertaining to automatic UFLS that are addressed in PRC-006-1. The purpose of EOP-003-2 – Load Shedding Plans is to ensure that a Balancing Authority and Transmission Operator operating with insufficient generation or delivery system capacity during a system event have the capability and authority to shed load rather than risk an uncontrolled separation or cascading of the Interconnection.

Additionally, to resolve potential discrepancies, NERC recommends the retirement of three existing FERC-approved Reliability Standards coincident with the implementation of the proposed standards. The three standards proposed for retirement are PRC-007-0, PRC-009-0, and EOP-003-1. NERC also requests FERC approval to retire the NERC Board of Trustees' approved PRC-006-0 standard as addressed in this filing.

[3] Energy Policy Act of 2005, 16 U.S.C. § 824o (2010).

b. Basis for Approval of Proposed Reliability Standard

Section 39.5(a) of FERC's regulations requires the ERO to file with FERC for its approval each Reliability Standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to an approved Reliability Standard that the ERO proposes to be made effective. FERC has the regulatory responsibility to approve standards that protect the reliability of the bulk power system. In discharging its responsibility to review, approve, and enforce mandatory Reliability Standards, FERC is authorized to approve those proposed Reliability Standards that meet the criteria detailed by Congress:

> *The Commission may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest*.[4]

When evaluating proposed Reliability Standards, FERC is required by statute to give "due weight" to the technical expertise of the ERO. Order No. 672 provides guidance on the fifteen factors FERC will consider when determining whether proposed Reliability Standards meet the statutory criteria.[5]

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Standard Processes Manual*, which is incorporated into the Rules of Procedure as Appendix 3A.[6] In its ERO Certification Order, FERC found that NERC's proposed rules provide for reasonable notice and opportunity

[4] Section 215(d)(2) of the FPA, 16 U.S.C. § 824o(d)(2) (2010).
[5] Order No. 672 at PP 320-338.
[6] FERC approved the new Reliability *Standard Processes Manual* on September 3, 2010 (FERC Docket No. RR10-12-000), which replaces the previous FERC-approved *Reliability Standards Development Procedure Version 7* in its entirety. NERC developed these standards in accordance with the *Reliability Standards Development Procedure Version 7* until the *Standard Processes Manual* was approved on September 3, at which time that procedure was used to complete development of the proposed standards.

for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards.[7]

The Development Process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard for submission to FERC.

Three versions of the Standards Authorization Request (SAR) were developed between 2006 and March, 2007. Six versions of PRC-006-1 – Automatic Underfrequency Load Shedding were developed between March, 2007 and October, 2010. The drafting team developed four drafts of EOP-003-2 – Load Shedding Plans in 2010. An initial ballot was conducted in July, 2010, and two successive ballots were conducted between July, 2010 and early October, 2010. A final recirculation ballot was conducted in mid-October, 2010. The ballot achieved a weighted segment vote of 84.67%.

The proposed Reliability Standards set out in **Exhibit A** have been developed and approved by industry stakeholders using the procedures described in NERC's *Standard Processes Manual*. A narrative of this process appears in section VI of this filing. These proposed Reliability Standards were approved by the NERC Board of Trustees on November 4, 2010.

IV. JUSTIFICATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS

a. Section Overview

This section summarizes the development of the two proposed Reliability Standards and identifies the associated necessary changes or retirements to other FERC-approved Reliability

[7] Order No. 672 at PP 268, 270.

Standards. The discussion in this section also demonstrates that the proposed Reliability Standards meet the criteria for approval established by FERC. That is, the proposed Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[8]

Exhibit D includes the Consideration of Comments documents, which includes a discussion of how comments were considered by the standard drafting team in developing the proposed standards. The standard drafting team roster is provided in **Exhibit E**. The complete development record for the proposed Reliability Standards, including the Implementation Plan referenced in this filing, is available in **Exhibit F**. This extensive development record includes successive drafts of the Reliability Standards, the ballot pool, the final ballot results by registered ballot body members, and stakeholder comments received during the development of these Reliability Standards.

The discussion of the two proposed Reliability Standards below is followed by discussion of the various standards that are recommended for retirement when the new Reliability Standards becomes effective.

DISCUSSION OF PRC-006-1

NERC proposes the addition of a new Reliability Standard PRC-006-1 to the current suite of FERC-approved Reliability Standards. PRC-006-1 is presented in **Exhibit A** of this filing.

In order to approve a Reliability Standard proposed by the ERO, FERC must determine, after notice and opportunity for public hearing, that the standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[9] In Order No. 672, FERC identified a

[8] *See* Order No. 672.
[9] Section 215(d)(2)(A) of the FPA; 18 C.F.R. §39.5.

number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The proposed Reliability Standard is necessary for reliability because Underfrequency Load Shedding programs provide last resort system preservation measures by shedding load during system disturbances that result in substantial imbalances between load and generation. The proposed Reliability Standard establishes common performance characteristics that all UFLS programs must meet. UFLS programs with differing design specifications can be successfully coordinated if they are designed to achieve the same system performance characteristics, even across interconnected regions.

The following discussion describes how the proposed PRC-006-1 standard meets the guidelines identified by FERC in Order No. 672 as necessary to concluding a Reliability Standard meets the statutory criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal

Order No. 672 at P 321. *The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cyber security protection.*

The purpose of the proposed standard, PRC-006-1 – Automatic Underfrequency Load Shedding, is to establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures. UFLS programs provide last resort system preservation measures by shedding load during system disturbances that result in substantial imbalances between load and generation. The proposed

PRC-006-1 standard is intended to replace PRC-006-0—Development and Documentation of Regional UFLS Programs, which was not approved by the Commission in Order No. 693, PRC-007-0—Assuring Consistency of Entity Underfrequency Load Shedding Programs, and PRC-009-0—Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event, both approved in Order No. 693.

The proposed standard, PRC-006-1, establishes common performance characteristics that all UFLS programs must meet. The standard requires that Planning Coordinators design and document Underfrequency Load Shedding programs that perform as specified in Requirement R3 of the proposed standard. The proposed standard does not specify program specifics such as load shedding frequency thresholds, step sizes, and time delays. Prescribing specific UFLS program parameters for the entire continent is unnecessary for reliability and hinders flexibility necessary to adapt UFLS designs to system characteristics specific to interconnections and regions. A uniform set of prescribed UFLS program parameters may not provide adequate system performance for all possible electrical islands that may form during a disturbance due to differences in system characteristics present in the four interconnections or even within different regions in the Eastern Interconnection. For example, the WECC Coordinated Off-Nominal Frequency Load Shedding Plan allows different set points and associated armed load for two sub-areas that may form within the Western Interconnection, provided they conform to the same methodology, assumptions, and objectives as the Coordinated Plan.

Requirements R1 and R2 establish the basis for the UFLS program design assessments by requiring that the Planning Coordinator establish island identification criteria (Requirement R1) and then apply the criteria to identify islands as the basis for assessing the design of its UFLS program (Requirement R2).

Requirement R3 requires each Planning Coordinator to develop a UFLS program including notification of and a schedule for implementation by the UFLS entities within its area that meet specific performance characteristics (subrequirements 3.1 through 3.3) in simulations of underfrequency conditions resulting from an imbalance of up to 25 percent within the identified island. Requirement R3 specifies the performance criteria that each Planning Coordinator's UFLS programs must be designed to achieve in simulation. These criteria consist of frequency versus time performance characteristic curves that frequency must remain within when simulating underfrequency events. Additionally, the criteria include V/Hz limits at generating plants that must not be exceeded to avoid unnecessary protection system operation that could remove that generation and make underfrequency conditions worse. The performance characteristics specified in subrequirements 3.1 and 3.2 were coordinated with generator trip setting boundaries specified in PRC-024-1—Generator Frequency and Voltage Protective Relay Settings appropriate to maintain margin between the system frequency excursions allowed in PRC-006-1 and generator trip settings.

Requirement R3 also requires the Planning Coordinator to develop a schedule for implementation by the UFLS entities along with the program. The applicability section of the standard defines UFLS entities as entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more Transmission Owner and Distribution Provider. Requirement R3 is important because the UFLS entities will need transition time to become compliant should the program be altered or redesigned. UFLS performance requirements were established for an imbalance scenario defined by a 25 percent imbalance between load and generation. This threshold was selected based on the common characteristics

of the existing regional programs. This threshold requirement supports the reliability of the bulk power system by specifying that UFLS programs must be designed for imbalance scenarios that may be observed during major system disturbances.

Requirement R4 requires that the Planning Coordinator conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. Subrequirements 4.1 through 4.7 of Requirement R4 specify that the simulation must model under and overfrequency trip settings of individual and aggregate generating units connected to the BES that trip above and below the generator underfrequency and overfrequency trip modeling curves contained in Attachment 1 to the standard (subrequirements 4.1 through 4.6). In addition, the simulation must model any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

Requirement R5 and Requirement R13 establish coordination requirements for Planning Coordinators whose areas or portions of whose areas are part of an island identified by it or another Planning Coordinator that includes multiple Planning Coordinator areas or portions of those areas. Requirement R5 states that the Planning Coordinator must coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island, through specific actions that include either (1) developing a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island; or (2) conducting a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified

island; or (3) conducting an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and to the ERO.

Requirement R13 requires that each Planning Coordinator, in whose area a bulk electric system islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, must coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event by either (1) conducting a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event; or (2) conducting an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event; or (3) conducting an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identifying differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and to the ERO.

Requirements R6 through R8 establish requirements to maintain a UFLS database and exchanging data to maintain the UFLS database. Each Planning Coordinator is required to maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities in Requirement R6. Requirement R7 requires the Planning Coordinators to exchange UFLS databases within 30 calendar days of a request. Finally, Requirement R8 requires that each UFLS entity provide its data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.

Requirements R9 through R10 are the implementation requirements of the proposed standard. Requirement R9 requires that each UFLS entity provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. Requirement R10 requires each Transmission Owner to provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.

Requirements R11 and R12 require the Planning Coordinators, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, to conduct and document an assessment (R11) and, should the assessment identify deficiencies, the Planning Coordinators must conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation (R12).

Requirement R14 establishes a method for the UFLS entities and Transmission Owners to provide input on the UFLS program and the schedule for implementation by requiring the Planning Coordinators to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the UFLS program, including the schedule for implementation; the UFLS design assessment and; the format and schedule of UFLS data submittal (subrequirements 14.1 through 14.3).

2. *Proposed Reliability Standards must contain a technically sound method to achieve the goal*

Order No. 672 at P 324. *The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons*

The proposed standard, PRC-006-1 –Automatic Underfrequency Load Shedding, establishes a technically sound method to achieve the goal of arresting declining frequency and assisting recovery of frequency following underfrequency events. The proposed standard establishes a framework for developing, designing, assessing and coordinating UFLS programs.

Requirements R1 and R2 require development of island identification criteria and application of the criteria to identify islands as a basis for assessing the design of the UFLS program. When evaluating the performance of UFLS programs, it is necessary to identify islands on which to base the evaluation. Requirement R1 requires Planning Coordinators to consider how islands involving their areas may be identified and develop and document the criteria. Their consideration will need to include any islands that may have formed in the past, or

any that may have some probability, as determined in system studies, of occurring in the future. By making this a requirement, the standard drafting team is ensuring that all Planning Coordinators are not only identifying islands within their Planning Coordinator areas, but they are also considering interconnected portions of the BES in adjacent Planning Coordinator and Regional Entity areas that may form islands. Requirement R2 requires Planning Coordinators to identify the islands for use in the UFLS assessments (Requirement R4). Subrequirements 2.1, 2.2, and 2.3 serve as a checklist of items that the entity must consider when identifying islands. Subrequirement 2.3 is included in order to continue the present practice of coordinating UFLS systems on a regional basis by requiring all Planning Coordinators in a region to assess the collective performance of the UFLS systems in the region as a whole. In satisfying this requirement, this same assessment may be done by each Planning Coordinator individually, but in the interest of efficiency, it would be advantageous that all Planning Coordinators collaborate on a single regional assessment.

Requirement R3 requires each Planning Coordinator to develop a UFLS program including notification of and a schedule for implementation by the UFLS entities within its area that meet specific performance characteristics (subrequirements 3.1 through 3.3) in simulations of underfrequency conditions resulting from an imbalance of up to 25 percent within the identified island. This requirement specifies the performance criteria that each Planning Coordinator's UFLS programs must be designed to achieve in simulation. These criteria consist of frequency versus time performance characteristic curves that frequency must remain within when simulating underfrequency events. Additionally, the criteria include V/Hz limits at generating plants that must not be exceeded to avoid unnecessary protection system operation that could remove that generation and make underfrequency conditions worse. The performance

characteristics specified in Parts 3.1 and 3.2 were coordinated with generator trip setting boundaries specified in PRC-024-1—Generator Frequency and Voltage Protective Relay Settings so as to maintain consistent margins between the system frequency excursions allowed here and generator trip settings. The requirement also requires the Planning Coordinator to develop a schedule for application by the UFLS entities along with the program. This is important because the UFLS entities will need transition time to become compliant should the program be altered or redesigned. UFLS performance characteristics were established for a 25 percent imbalance between load and generation. While most regions define the imbalance as a generation deficiency (*i.e.*, load – generation/load), some regions treat this as an overload (*i.e.*, load-generation/generation). The equation in this requirement eliminates ambiguity and potential confusion, because, for example, a 25 percent generation deficiency would result in a 33 percent overload. Requirement R3 requires that UFLS programs be designed to achieve the specified performance characteristics for imbalances between load and generation of up to 25 percent. This threshold was selected based on the common characteristics of the existing regional programs. This threshold supports reliability of the BES by providing an effective safety net for imbalances that may be observed during major system disturbances.

Requirement R4 requires each Planning Coordinator to conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. Subrequirements 4.1 through 4.7 specify items that the simulation must model. Subrequirements 4.1 through 4.6 are included to make sure that any generator trip settings that do not conform to the requirements set forth in PRC-024-1—Generator Frequency and Voltage Protective Relay Settings are factored into the analyses, and

the UFLS program design will accommodate the possible loss of generation in these instances in addition to the initial load-generation imbalance. Subrequirement 4.7 is included to make sure that any automatic load restoration schemes to limit high frequency conditions are also factored into the analyses. Subrequirements 4.1 through 4.3 pertain to underfrequency coordination with generators, and subrequirements 4.4 through 4.6 pertain to overfrequency coordination with generators. Subrequirement 4.7 pertains to automatic load restoration schemes. The assessment is to be performed every five years to account for system changes that may alter the effectiveness of the UFLS program, or sooner when a UFLS event occurs to incorporate information obtained through analysis of system events.

Requirement R5 and Requirement R13 require that each Planning Coordinator coordinate with other Planning Coordinators by defined actions when its Planning Coordinator area or portions of its area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas. Requirement R5 specifically requires that the Planning Coordinator coordinate its UFLS design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through specific actions identified in Requirement R5. This requirement was written to foster coordination among Planning Coordinators when an island is identified which overlaps multiple Planning Coordinator areas. In a fashion similar to R5, where a UFLS event included portions of two or more Planning Coordinator areas, the assessment of that event (per R11) must be acceptable to each of the respective Planning Coordinators in order to conclude that a valid event assessment has been performed. Requirement R13 ensures that acceptance.

Requirements R6 through R8 establish responsibilities related to defining, collecting, and maintaining data necessary to support UFLS assessments. Requirement R6 requires each

Planning Coordinator to maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. The UFLS assessments (R4) will require the simulation of UFLS automatic load tripping and other automatic switching actions where applicable. This requirement assigns responsibility to the Planning Coordinators to ensure that the necessary data will be maintained in a database. Should significant UFLS events occur, this requirement also serves to ensure data availability to conduct the event assessments required by R11. Requirement R7 requires that each Planning Coordinator provide its UFLS database to other Planning Coordinators within its Interconnection within 30 calendar days of a request. Where identified islands include portions of two or more Planning Coordinator areas, UFLS assessments will need to include the UFLS data applicable to each of those areas. This requirement ensures the necessary sharing of that data between Planning Coordinators. Finally, Requirement R8 requires that each UFLS entity provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of the UFLS database. This requirement assigns responsibility to the Distribution Providers and Transmission Owners that have UFLS relays implemented as a part of the Planning Coordinator's UFLS program to supply the data necessary to populate the applicable Planning Coordinator's UFLS database.

Requirements R9 and R10 establish the implementation framework for the UFLS program. Requirement R9 requires that each UFLS entity provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. This requirement ensures that the equipment and relay settings necessary to implement the automatic

load shedding specified by the Planning Coordinator's UFLS program are in place and ready to trip load. Requirement R10 requires that each Transmission Owner provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. Similar to Requirement R9, if there are any other automatic switching actions besides load tripping specified in the UFLS program design, this requirement ensures that that switching capability is in place and ready to operate. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Owner; Requirement R10 focuses on switching of devices performed by the Transmission Owner to control over-voltage as a result of underfrequency load shedding. Requirement R10 was added to address control of overvoltage conditions during underfrequency events (*e.g.*, the West has very long transmission corridors which can create an overvoltage condition when those lines are unloaded, such as during an underfrequency event).

Requirements R11 and R12 relate to event assessments. Requirement R11 requires that each Planning Coordinator, in whose area a bulk electric system islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation that evaluates the performance of the UFLS equipment (subrequirement 11.1), and the effectiveness of the UFLS program (subrequirement 11.2). It is desirable to analyze underfrequency events that have involved UFLS operations in order to determine how successful the UFLS program was in arresting frequency decline and restoring load-generation balance. This requirement assigns

responsibility to the Planning Coordinator to perform an event assessment. PRC-009-0 Requirement R1 currently requires an event assessment of the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. Requirement R12 requires that each Planning Coordinator, in whose islanding event assessment (subrequirement R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. As a follow-up to R11, this requirement ensures that improvements to the UFLS program design will be considered that address UFLS program deficiencies identified in a UFLS event assessment.

Finally Requirement R14 is a coordination requirement that requires the Planning Coordinator to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the UFLS program, including a schedule for implementation (subrequirement 14.1) and the UFLS design assessment (subrequirement 14.2). This requirement was added in response to industry comments on the standard expressing concern that the UFLS entities and Transmission Owners should have a role in the process of defining the UFLS program and schedule for implementation. The standard drafting team considered the role of the Planning Coordinator and the coordination activities that the Planning Coordinator performs to meet its obligations. However, the standard drafting team agreed that it would be beneficial to involve explicitly the UFLS entities and the Transmission Owners in the process of defining the UFLS program and the schedule for implementation. These entities may

provide information based on practical implementation experience that improves the overall effectiveness of the UFLS program.

3. Proposed Reliability Standards must be applicable to users, owners, and operators of the bulk power system, and not others

Order No. 672 at P 322. *The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.*

The proposed standard is applicable to users, owners, and operators of the bulk power system and not others. The standard applies to Planning Coordinators, UFLS entities and Transmission Owners. Section 4.2 of the Applicability section explains that UFLS entities are all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include Transmission Owners or Distribution Providers.

The Planning Coordinators are the most appropriate entities to be assigned responsibility for the design, assessment and coordination of the UFLS programs. As defined in version 5 of the Functional Model, the Planning Coordinator is:

> The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area, and coordinates those plans with adjoining Planning Coordinator areas.

In addition, the Functional Model explains that:

> While the area under the purview of a Planning Coordinator may include as few as one Transmission Planner and one Resource Planner, the Planning Coordinator's scope of activities may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities.

Therefore, based on the definition of the role and based on existing practice, the Planning Coordinator is appropriately assigned the UFLS design, assessment and coordination activities.

The requirements related to the implementation of the UFLS program are assigned to the UFLS entities and Transmission Owners. For decades, underfrequency load shedding programs have been implemented by different entities depending on how the transmission system was constructed and owned. In some parts of the country, Distribution Providers accomplish this task, in others it is the Transmission Owners. Indeed, the set of standards intended to be replaced by this new standard allowed either of these registered entities, along with others in some cases, to accomplish the task of owning and operating UFLS relays. Because of this historical nature of the entities involved in the implementation of UFLS programs, and consistent with the Applicability sections in the PRC-007-0 and PRC-009-0 standards that this standard is intended to replace, the Transmission Owners and the Distribution Providers will have a role in implementing UFLS programs. Requirement R10, which includes the automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding, is a function which would be performed by Transmission Owners specifically and therefore provides a basis for assigning Requirement R10 to Transmission Owners rather than UFLS entities (which includes Distribution Providers). UFLS entities, that may be Distribution Providers, Transmission Owners, or both, are responsible for the implementation of the UFLS program by providing automatic tripping of Load in accordance with the UFLS program and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator are in which it owns assets (Requirement R9).

4. Proposed Reliability Standards must be clear and unambiguous as to what is required and who is required to comply

Order No. 672 at P 325. *The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.*

The proposed standard is clear and unambiguous as to what is required and who is required to comply. Requirements R1 through R7 establish requirements for the Planning Coordinator related to identifying islands, designing and assessing the UFLS program, coordinating the UFLS program with other Planning Coordinators, and maintaining the UFLS database including exchanging information with other Planning Coordinators. Requirements R11 through R13 are also assigned to the Planning Coordinator and require them to conduct event assessments, coordinate such assessments with other Coordinators where necessary, and consider modifying UFLS program design should any design deficiencies be identified in the event assessments. Requirement R14 is assigned to the Planning Coordinator and requires them to coordinate by way of responding to comments submitted by UFLS entities (DPs, TOs or both) on the UFLS program including the schedule for implementation, the UFLS design assessment, and format and schedule of UFLS data submittal.

Requirements R8 and R9 are assigned to the UFLS entities. Requirement R8 requires that they provide data to their Planning Coordinators according to the format and schedule specified by the Planning Coordinators to support maintenance of each Planning Coordinator's UFLS database. Requirement R9 requires that the UFLS entities provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by their Planning Coordinators in each Planning Coordinator area in which they own assets.

Requirement R10 is assigned to the Transmission Owner. Requirement R10 requires that the Transmission Owner provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the

Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.

5. Proposed Reliability Standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation

Order No. 672 at P 326. *The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply*.

The proposed standard includes clear and understandable consequences and a range of penalties for a violation by establishing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement. **Exhibit A** to this filing containing the proposed standard also includes the proposed VRFs and VSLs by Requirement. Additionally, the VRFs and VSLs proposed for approval are discussed later in this filing.

6. Proposed Reliability Standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner

Order No. 672 at P 327. *There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.*

The proposed standard identifies clear and objective measures for compliance by establishing measures for each requirement. The measures support the requirements by identifying what evidence or types of evidence could be used to show that an entity is compliant with the requirement. **Exhibit A** to this filing includes the proposed measures by Requirement.

7. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost

Order No. 672 at P 328. *The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.*

The proposed standard achieves a specific reliability goal of establishing design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events. UFLS programs provide last resort system preservation measures by shedding load during system disturbances that result in substantial imbalance between load and generation. The proposed standard does not reflect "best practices" without regard to implementation cost. The standard drafting team reviewed the regional practices in place during the standard development to understand existing practice. The standard drafting team took into consideration the current practices in developing one set of common performance characteristics that all regional underfrequency load shedding programs must meet (Requirement R3). The drafting team concluded that UFLS programs with differing design specifications can be successfully coordinated if they are designed to achieve the same system performance characteristics, even across interconnected regions, and that there is not one best way to design a UFLS program. In light of these observations, the drafting team determined that most effective and efficient method to achieve the desired reliability goal is to establish common performance characteristics, because prescribing uniform UFLS program parameters would require most, if not all, entities to modify their UFLS equipment for little or no added reliability benefit.

In addition to establishing common performance characteristics, the proposed standard establishes additional requirements for the Planning Coordinators to ensure that the performance characteristics are applied consistently and in a coordinated manner. The Planning Coordinators are required to define island identification criteria and apply that criteria to identify islands to serve as a basis for assessing the design of the UFLS program (Requirement R1 and R2); perform design assessments on a defined periodic basis (Requirement R4); coordinate

assessments with other Planning Coordinators by defined actions should a Planning Coordinator's area (or portions of its area) be contained in an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas (or portions of those areas) (Requirement R5); conduct, document, and coordinate with other Planning Coordinators where necessary on UFLS event assessments, and consider design changes that could address deficiencies that may be identified in an event assessment (Requirement R11 through R13); and involve the UFLS entities in the Planning Coordinator's responsibilities established in the standard by requiring the Planning Coordinators to respond to written comments on the UFLS program including the schedule for implementation, UFLS design assessment, and the format and schedule of UFLS data submittal (Requirement R14).

The standard also establishes requirements for the Planning Coordinators and UFLS Entities to support the exchange of information necessary to design and assess performance of UFLS programs by way of the establishment of a UFLS database and exchange of data to populate the database (Requirements R6 through R8).

Additionally, the standard establishes requirements for the UFLS entities and Transmission Owners to ensure effective and efficient implementation of the UFLS programs. The UFLS entities are required to provide load shedding, and the Transmission Owners are required to provide automatic switching of capacitor banks, Transmission Lines, and reactors as necessary to control over-voltage that may result from underfrequency load shedding as determined by the Planning Coordinator(s) (Requirements R9 and R10).

8. ***Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability***

Order No. 672 at P 330. *A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in*

operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

The Reliability Standard does not aim at a "lowest common denominator." Regional criteria for UFLS programs have traditionally specified detailed parameters that define quantities such as the number of steps in the program, the load shed at each step, and the frequency threshold and time delay at each step. Adopting such an approach in the proposed continent-wide UFLS standard could lead to selection of parameters based on the lowest common denominator among the existing UFLS programs. Rather than following this approach, the proposed standard establishes common performance characteristics that all UFLS programs must meet to effectively protect Bulk-Power System reliability. These performance characteristics were selected to establish requirements on the system performance during and following an underfrequency event. It is more appropriate to define the effectiveness of UFLS programs in terms of parameters that directly measure system performance (*i.e.*, frequency and voltage versus time) rather than indirect measures such as the amount and timing of load shedding. The performance characteristics were selected to require that UFLS programs are designed to arrest declining frequency at a level that coordinates with capabilities of system equipment, particularly generation equipment, and that following UFLS operation, frequency remains within equipment capabilities and is restored to a sustainable level from which operator action can restore normal frequency. The boundary conditions established in the proposed standard within which UFLS programs must be designed to operate were selected based on coordination with generator capabilities and generator protection requirements in consultation with the Generator Verification Standard Drafting Team and a review of IEEE Guides on design and protection of generators and power transformers.

9. *Proposed Reliability Standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability*

Order No. 672 at P 330. *A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.*

The proposed Reliability Standards do not reflect any differentiation in requirements based on entity size. In addition, the proposed standard was posted for public comment on three occasions during the development of the standard prior to balloting. During these postings, no entities expressed concerns that the requirements would be too costly for smaller entities to implement. Nevertheless, the proposed PRC-006-1 standard does provide the opportunity for Planning Coordinators to consider input from smaller entities when developing the UFLS program. Some UFLS programs do make allowances regarding the practicality of smaller entities to implement the UFLS program parameters, and PRC-006-1 allows Planning Coordinators to continue this practice so long as the reliability objectives of this standard are met (*i.e.*, the UFLS program, including allowances for smaller entities, meets all of the performance characteristics embodied in this standard).

10. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one area or approach

Order No. 672 at P 331. *A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System; to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.*

The requirements in this Reliability Standard apply throughout North America, with two exceptions. The proposed standard includes a Variance for the Western Interconnection and another Variance for the Quebec Interconnection.

In the aftermath of system-wide disturbances occurring within the Western Interconnection on July 2 and 3 and August 10, 1996, President Clinton appointed a "Blue Ribbon" panel to perform a comprehensive assessment of these disturbances and make recommendations to enhance reliability within the Western Interconnection. The investigations culminated in two reports: the *WSCC Disturbance Report for the Power System Outages that Occurred on the Western Interconnection on July 2, 1996 and July 3, 1996*, and *WSCC Disturbance Report for the Power System Outage that Occurred on the Western Interconnection on August 10, 1996* ("Disturbance Reports"). The Disturbance Reports' recommendations identified several reliability issues for further investigation. One of these issues was the efficacy of existing policies and procedures related to off-nominal frequency (UFLS programs), the purposes of which are to arrest potential system collapses due to large frequency deviations, minimize associated adverse impacts caused by cascading outages, and aid in quickly restoring the system to normal operations.

The Western Electricity Coordinating Council ("WECC") Planning Coordination Committee ("PCC") and the Operating Committee ("OC") developed a coordinated off-nominal frequency load shedding and restoration plan for the Western Interconnection in the fall of 1997 ("1997 Coordinated Plan"). The WECC Board of Trustees approved the 1997 Coordinated Plan on December 4, 1997.

In 2009, the WECC PCC and OC formed a task force to review the effectiveness of the existing protection relays associated with the 1997 Coordinated Plan. The results indicated that

WECC members' relay settings conform to the 1997 Coordinated Plan performance requirements, both in arresting frequency decline before frequency reaches 58.0 Hz and in recovering frequency to 59.5 Hz or higher. These results also indicated that UFLS relays will not activate until there has been a cascading disturbance across multiple entities' systems. In addition, none of the Western Interconnection's sub-areas will experience an off-nominal frequency event due to either single or dual most severe contingency losses of generation resources if the losses occur within known island configurations.

The members of WECC recognize the need for a common plan for underfrequency load shedding. The members of WECC have agreed to follow and operate their systems in accordance with the Coordinated Plan as an essential element of a well-planned and operated Western Interconnection electric system.

WECC believes it is necessary to maintain the reliability benefits of the WECC Coordinated Plan as NERC moves forward with the revision to PRC-006-1—Automatic Underfrequency Load Shedding. The language in the proposed variance is intended to ensure that the Planning Coordinators in the Western Interconnection continue to implement the WECC Coordinated Plan rather than developing new UFLS Plans that are not fully coordinated with the WECC Coordinated Plan. The variance language requires this coordination, while still requiring the individual Planning Coordinators to meet the system performance levels identified in the NERC Continent-wide Reliability Standard.

Earlier in 2009, NPCC identified the need for a variance to the standard for the Québec Interconnection within NPCC. Due to the physical characteristics of the Québec system, the UFLS program in Québec arrests frequency at a lower threshold and permits higher frequency overshoot than allowed in the proposed standard. The installed generation in the Québec

Interconnection is 98 percent hydraulic generation, allowing wider tolerances on frequency performance without jeopardizing reliability. The variance also establishes a different capacity threshold for the generating units for which underfrequency and overfrequency trip settings must be modeled to address concerns that by 2020, 10 percent of the installed capacity in Québec may be located at plants less than 75 MVA. The Standards Committee appointed a member from the Québec Interconnection to the drafting team to develop the variance for Québec. Working closely with this representative, the team developed the variance to Requirement R3 parts 3.1 and 3.2 and Requirement R4 parts 4.1 and 4.2. The variance to these requirements reference separate under and overfrequency curves included as attachment 1A to the standard.

11. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid

Order No. 672 at P 332. *As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.*

The requirements in the Reliability Standards do not cause negative effect on competition or restriction of the grid. Automatic UFLS is a program that does not impact the normal grid operation until there is a serious disturbance. It is intended solely to prevent cascading outages and blackouts. It is a last tier of system protection against cascading and blackouts that has no effect and causes no restrictions during normal operating conditions.

12. The implementation time for the proposed Reliability Standards must be reasonable

Order No. 672 at P 333. *In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.*

Given the complexity, and importance of the program, the Implementation Plan (see **Exhibit D**) does not allow an excessively long time period for entities to become fully compliant, but allows them sufficient time to transition and install the necessary processes to become compliant. The implementation plan specifies that compliance with the new version PRC-006-1—Automatic Underfrequency Load Shedding Reliability Standard, Requirements R1 through R14, with the one exception for Requirement R4, subrequirements 4.1 through 4.6, is effective one year following the first day of the first calendar quarter after applicable regulatory approvals.

The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time: 1) to develop, modify, or validate (to determine that an existing program meets required performance characteristics) existing UFLS programs and 2) to establish a schedule for implementation, or validate a schedule for completion of program revisions already in progress. Transmission Owners and Distribution Providers shall comply with the schedule determined by the Planning Coordinator but no sooner than the effective date of the standard.

With the exception for PRC-024-1, there are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Underfrequency Load Shedding standard and any associated regional reliability standards can be implemented. Subrequirements 4.1 through 4.6 of Requirement R4 of the Underfrequency Load Shedding standard shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1. PRC-006-1 Subrequirements 4.1 through 4.6 of Requirement R4 require that the Planning Coordinator model any generator trip settings that do not conform to the requirements set forth in PRC-024-1—

Generator Frequency and Voltage Protective Relay Settings to ensure that they are factored into the analyses (subrequirements 4.1 through 4.6). The UFLS program design will need to accommodate the possible loss of generation in these instances in addition to the initial load-generation imbalance. Because this requirement is dependent on data that is provided by way of another standard, PRC-024-1—Generator Frequency and Voltage Protective Relay Settings, many industry commenters expressed concern that the responsibilities outlined in PRC-006-1 Requirement R4, subrequirements 4.1 through 4.6 could not be fulfilled until PRC-024-1 was approved and effective. As a result, the standard drafting team modified the implementation plan to include a dependency on PRC-024-1 approval as described above.

Compliance with the revised EOP-003-2 — Load Shedding Plans reliability standard is effective one year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required). The effective date for EOP-003-2 was selected to ensure that requirements regarding automatic UFLS programs are not retired from this standard until the requirements in PRC-006-2 are effective.

13. The Reliability Standard Development Process must be open and fair

Order No. 672 at P 334. *Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.*

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Standard Processes Manual*,

which is included in the NERC Rules of Procedure as Appendix 3A. In its ERO Certification Order, FERC found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. The Development Process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard for submission to FERC. The drafting team developed this standard by following the Reliability Standards Development Process. In this case, the proposed standards were publicly posted for comment on three occasions between 2008 and 2010. The standard drafting team considered comments from the industry and revised the standards and implementation plan accordingly. The standards were posted for initial ballot in July, 2010, with two additional successive ballots conducted thereafter, and a final recirculation ballot was conducted in October 2010. A total of six drafts of the PRC-006-1 standard were developed and a total of four drafts of EOP-003-2 were developed. The ballot achieved a weighted segment vote of 84.67%

14. Proposed Reliability Standards must balance with other vital public interests

Order No. 672 at P 335. *Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.*

The Reliability Standard does not conflict with any vital public interests. Responding successfully to system disturbances which result in frequency decline is a vital public interest.. Compliance with this standard supports the reliability of the interconnected systems by assisting in the prevention of cascading outages and blackouts.

15. Proposed Reliability Standards must not conflict with prior FERC Rules or Orders

Order No. 672 at P.444. *a potential conflict between a Reliability Standard under development and a Transmission Organization function, rule, order, tariff, rate schedule, or agreement*

accepted, approved, or ordered by the Commission should be identified and addressed during the ERO's Reliability Standard Development Process.

This petition addresses the FERC Order No. 693 directive to modify the PRC-006-1 – Automatic Underfrequency Load Shedding and EOP-003-2 – Load Shedding Plans Reliability Standards. The proposed standards establish a safety net that safeguards the system from cascading events by requiring that all UFLS programs meet common performance characteristics.

Additionally, while FERC Order No. 693 directed that the function of establishing the UFLS program requirements would pass from the Regional Reliability Organization (RRO) to the Regional Entity, the proposed standard, PRC-006-1 – Automatic Underfrequency Load Shedding proposes that the Planning Coordinator design and assess the UFLS program for its Planning Coordinator area. Accordingly, the proposed PRC-006-1 standard included herein for approval establishes an equally effective method of achieving the reliability goal by assigning responsibility to an entity that is suited with the tools and wide-area view to coordinate the development of a UFLS program. Because Planning Coordinators do not generally have a region-wide view in their assessments, Requirements R2, subrequirement 2.3 is included to continue the present practice of coordinating UFLS systems on a regional basis. Requirements R5 and R13 require coordination among Planning Coordinators across Planning Coordinators boundaries and across Regional Entity boundaries within an interconnection when islands are identified through system studies or through system events that may cross Planning Coordinator or Regional Entity boundaries.

16. Proposed Reliability Standards must consider any other relevant factors

Order No. 672 at P 323. *In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.*

Order No. 672 at P 337. *In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.*

No other factors for FERC's consideration were identified in the development of these proposed standards.

Retirement of PRC-006-0, PRC-007-0, and PRC-009-0

To resolve potential discrepancies, NERC recommends the retirement of two existing FERC-approved Reliability Standards, PRC-007-0, and PRC-009-0, and the NERC Board of Trustees approved PRC-006-0 concurrent with the implementation of the proposed standard, PRC-006-1. The requirements contained in PRC-006-0, PRC-007-0, and PRC-009-0 were reviewed during the development of PRC-006-1—Automatic Underfrequency Load Shedding to ensure that the requirements with a reliability objective are captured in the proposed standard. A detailed mapping of the existing requirements to the proposed standard, PRC-006-1, is included in **Exhibit C** to this filing.

PRC-006-0—Development and Documentation of Regional UFLS Programs is a NERC Board of Trustees approved standard and will be retired coincident with the implementation of the proposed standard, PRC-006-1. Requirement R1 in PRC-006-0 requires that the RRO develop, coordinate, and document an UFLS program. This requirement will be replaced by PRC-006-1 Requirement R3 that requires the Planning Coordinators to develop a UFLS program for a generation load imbalance of up to 25% that meets the performance characteristics in

subrequirements 3.1 through 3.3 in simulations. PRC-006-0 sub-requirement R1.1 requires that the RRO establish requirements for coordination of UFLS programs within the subregions, RRO and, where appropriate, among RROs. This requirement is captured in Requirement R5 and R13 in PRC-006-1. These two requirements establish specific coordination actions should a Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas.

Requirement R5 requires that the Planning Coordinator coordinate its UFLS program, and Requirement R13 requires the that Planning Coordinator in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the prescribed actions in Requirement R13.

PRC-006-0 Sub-requirement R1.2 specifies that the RRO must include frequency set-points (R1.2.1), the size of corresponding load shedding blocks (R1.2.2), and intentional and load tripping time delays (R1.2.3). Requirement R3 in PRC-006-1 captures the UFLS program specifics that the Planning Coordinator must include when designing its UFLS program. While the requirement does not include specific frequency-set points, it does specify frequency performance represented in Attachment 1 (parts 3.1 and 3.2) to the standard and specifies that voltage performance in part 3.3.

Sub-requirement R1.2.4 in PRC-006-0 requires that the RRO specify generation protection in the UFLS program. Generation protection is captured in PRC-006-1 by requiring that the Planning Coordinators ensure that volts per Hz do not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and do not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with the locations specified in 3.3.1 through 3.3.3.

Requirement R4 in PRC-006-1 requires that the Planning Coordinator conduct a UFLS assessment through dynamic simulation. The simulation must model under and over-frequency trip settings of the individual and plants/facilities in parts 4.1 through 4.6. Sub-requirements R1.2.5 and R1.2.6 of PRC-006-0 require that the RRO include tie tripping schemes and islanding schemes in the UFLS program. The replacement standard, PRC-006-1, requires that the Planning Coordinators identify islands by including any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System (Requirement R2 part 2.2).

Sub-requirement R1.2.7 of PRC-006-0 requires that the RRO specify automatic load restoration schemes in the UFLS program. The replacement standard, PRC-006-1, requirement R4 subrequirement 4.7 requires that the Planning Coordinator model any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment. Sub-requirement R1.2.8 in PRC-006-0 requires that the RRO include any other schemes that are part of or impact the UFLS programs in the details of the program. PRC-006-1 captures other schemes in Requirement R10 where the Transmission Owners are required to provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if

required by the UFLS program and schedule for application determined by the Planning Coordinator(s).

Sub-requirement R1.3 in PRC-006-0 requires that the RRO develop a UFLS program database, this database must be updated as specified in the RRO program (but at least every five years), and must include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems. Requirement R6, R7 and R8 in PRC-006-1 contain the UFLS database responsibilities. Requirement R6 requires that the Planning Coordinator maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. Requirement R7 requires that the Planning Coordinator provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request.

Finally, Requirement R8 requires that each UFLS entity provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.

Sub-requirement R1.4 in PRC-006-0 requires that the RRO conduct an assessment and document the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to a review of the frequency set points and timing, (R1.4.1) and dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation (R1.4.2). Requirements R4 and R12 in PRC-006-1 contain the assessment

responsibilities. Requirement R4 requires that the Planning Coordinators conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics, and Requirement R12 requires that the Planning Coordinator, in whose islanding event assessment (identified in Requirement R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation.

Requirement R2 in PRC-006-0 requires the RRO to provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days), and Requirement R3 requires that RRO provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days). Both of these requirements are addressed in Section 401.3 of the NERC Rules of Procedures, which provides:

> **Data Access** — All bulk power system owners, operators, and users shall provide to NERC and the applicable regional entity such information as is necessary to monitor compliance with the reliability standards. NERC and the applicable regional entity will define the data retention and reporting requirements in the reliability standards and compliance reporting procedures.

PRC-007-0—Assuring Consistency with Regional UFLS Program Requirements Requirement R1, requires that each Transmission Owner and Distribution Provider with a UFLS program (as required by its RRO) shall ensure that its UFLS program is consistent with its RRO's UFLS program requirements. This requirement is captured in the proposed standard PRC-006-1—Automatic Underfrequency Load Shedding Requirements R9 and R10, which requires UFLS entities to provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) (R9) and Transmission Owner to provide automatic switching of its existing capacitor banks,

Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) (R10).

PRC-007-0 Requirement R2 requires entities that own or operate a UFLS program (as required by its RRO) to provide, and annually update, its underfrequency data as necessary for its RRO to maintain and update a UFLS program database. PRC-006-1 captures this responsibility in Requirement R8 by requiring each UFLS entity to provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.

Finally, Requirement R3 in PRC-007-0 requires that the Transmission Owner and Distribution Provider that owns a UFLS program (as required by its RRO) to provide its documentation of that UFLS program to its RRO on request (within 30 calendar days). This requirement is captured in PRC-006-1 Requirement R8 because it contains the requirement that the UFLS entity shall provide the necessary data to support the UFLS database in the format and schedule specified by the Planning Coordinator.

PRC-009-0—UFLS Performance Following an Underfrequency Event, Requirement R1 requires that the Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its RRO) shall analyze and document its UFLS program performance in accordance with its RRO's UFLS program, and the analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. Requirement R1 goes on to specify in sub-requirements R1.1 through R1.4 that the responsible entities must include a description of the

events (R1.1); a review of the UFLS set points and tripping times (R1.2); a simulation of the event (R1.3) and; a summary of the findings (R1.4). PRC-006-1 Requirement R11 requires that each Planning Coordinator in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, conduct and document an assessment of the event within one year of event actuation to evaluate the performance of the UFLS equipment (subrequirement 11.1), and the effectiveness of the UFLS program (subrequirement 11.2).

Finally, Requirement R2 in PRC-009-0 requires that the Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its RRO) provide documentation of the analysis of the UFLS program to its RRO and NERC on request 90 calendar days after the system event. This existing requirement is addressed in the NERC Rules of Procedures, Section 401.3 Data Access, which requires all bulk power system owners, operators, and users to provide to NERC and the applicable regional entity such information as is necessary to monitor compliance with the reliability standards.

DISCUSSION OF EOP-003-2

NERC proposes the addition of a revised standard EOP-003-2, to the current suite of FERC-approved Reliability Standards. EOP-003-2 is presented in **Exhibit A** of this filing.

During the public comment periods several entities pointed out redundancy between EOP-003-1 – Load Shedding Plans and PRC-006-1 – Automatic Underfrequency Load Shedding. The Standards Committee approved a Supplemental SAR for posting on October 7, 2009 that expanded the SDT's scope to include EOP-003-1, but limiting that scope to only

eliminating references to automatic Underfrequency Load Shedding in EOP-003-1. The standard drafting team made minimal changes to EOP-003-1 – Load Shedding plans, and focused on eliminating redundancies between it and PRC-006-1 – Automatic Underfrequency Load Shedding. The drafting team clarified Requirement R2 by removing reference to underfrequency load shedding and focused the requirement on undervoltage conditions. Requirements R3 and R5 were modified by clarifying that the load shedding discussed in the requirements excludes automatic load shedding.

Additionally, the drafting team modified Requirements R4 and R7 to clarify that the load shedding discussed in the requirements is automatic under voltage load shedding. The Balancing Authority was removed from Requirements R2 and R4 because the frequency related aspects of these requirements were removed, leaving only consideration of automatic undervoltage load shedding in these two requirements.

b. Violation Risk Factor and Violation Severity Level Assignments

The proposed Reliability Standards include VRFs and VSLs. The ranges of penalties for violations are based on the applicable VRF and VSLs and will be administered based on the Sanctions table and supporting penalty determination process described in the FERC-approved NERC Sanction Guidelines, included as Appendix 4B in NERC's Rules of Procedure. Each primary requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Assignment of Violation Risk Factors

The UFLS Standard Drafting Team applied the following criteria when proposing VRFs for the requirements in PRC-006-1 – Automatic Underfrequency Load Shedding.

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.[10]

The team also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[11]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

[10] These three levels of risk are defined by NERC and recognized by FERC in the May 18, 2007 Order at P9, and the November 16, 2007 Order at Appendix A.
[11] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

In the VSL Order, FERC listed critical areas (from the Final Blackout Report[12]) where violations could severely affect the reliability of the Bulk-Power System:[13]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) — Consistency within a Reliability Standard[14]
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the drafting team considered FERC's VSL Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent

[12] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* U.S.-Canada Power System Outage Task Force, April 5, 2004.
[13] *Id.* at n. 15.

conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The team believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are 14 requirements in PRC-006-1 – Automatic Underfrequency Load Shedding:

- **VRF for PRC-006-1, Requirement R1: Medium**
  - FERC's Guideline 2 —Not applicable – this requirement does not have sub-parts.
  - FERC's Guideline 3 — Not applicable – this requirement is not related to similar reliability goals in other standards
  - FERC's Guideline 4 — This requirement is assigned a medium VRF because it is a planning requirement that while is administrative in nature is an input to other requirements in the standard that are assigned a higher VRF. Documenting criteria for selecting islands is an important step in designing a UFLS program but is administrative in nature. This is requirement, if violated, would not adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system but violation of the dependent requirements could have a higher impact on the bulk electric system. The assignment is consistent with the NERC VRF guidelines.
  - FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement R2: Medium**
  - FERC's Guideline 2 — This requirement has sub-parts, but these parts all support the parent requirement and do not have independent objectives.
  - FERC's Guideline 3 — Not applicable – this requirement is not related to similar reliability goals in other standards.
  - FERC's Guideline 4 — This requirement in part relies on the output of requirement R1, the criteria for selecting islands. Requirement R1 is a Medium VRF and this requirement is a Medium because the identification of islands for establishing a UFLS program is the intent of the requirement and is more than administrative in nature.
  - FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement R3: High**
  - FERC's Guideline 2 — This requirement has sub-parts, but these parts all support the parent requirement and do not have independent objectives.
  - FERC's Guideline 3 — Not applicable – this requirement is not related to similar reliability goals in other standards.
  - FERC's Guideline 4 — This requirement is assigned a High VRF because this requirement requires each Planning Coordinator to design a UFLS program that meets specific performance characteristics. This is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition. The assignment is consistent with the NERC definition of High VRF.
  - FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement R4: High**
  - FERC's Guideline 2 — This requirement has sub-parts, but these parts all support the parent requirement and do not have independent objectives.
  - FERC's Guideline 3 — Not applicable – this requirement is not related to similar reliability goals in other standards.
  - FERC's Guideline 4 — This requirement is assigned a High VRF because the reliability objective of this requirement is to perform an assessment of the UFLS program every five years. Violation of this requirement, by failing to validate the UFLS program through dynamic simulations, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition. The assignment is consistent with the NERC definition of High VRF.
  - FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement R5: Medium**
  - FERC's Guideline 2 — This requirement has sub-parts, but these parts all support the parent requirement and do not have independent objectives.
  - FERC's Guideline 3 — Not applicable – this requirement is not related to similar reliability goals in other standards.

- FERC's Guideline 4 — This requirement is assigned a Medium VRF because the reliability objective of this requirement is to reach concurrence with all other affected Planning Coordinators on assessment results when an island spans multiple areas. This requirement ensures coordination between Planning Coordinators knowing that islands may very possibly span multiple Planning Coordinator areas. While not administrative in nature, violation of this requirement, by failing to reach concurrence, would not necessarily under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition hence a Medium VRF. The assignment is consistent with the NERC definition of Medium VRF.
- FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement R6: Lower**
  - FERC's Guideline 2 — Not applicable – this requirement does not have sub-parts.
  - FERC's Guideline 3 — PRC-006-0 (not FERC approved) contains a similar requirement, Requirement R1.3, but does not have a VRF.
  - FERC's Guideline 4 — This requirement is assigned a Lower VRF because it requires that Planning Coordinators annually maintain a UFLS database. This requirement is clearly administrative; however, it is important that UFLS data/information is stored in a database. This requirement currently exists in PRC-006-0 Requirement R1.3. It is very unlikely that violating this planning requirement, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of the bulk electric system, or the ability to effectively control or restore the bulk electric system. The assignment is consistent with the NERC definition of Lower VRF.
  - FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.
- **VRF for PRC-006-1, Requirement R7: Lower**
  - FERC's Guideline 2 — Not applicable – this requirement does not have sub-parts.
  - FERC's Guideline 3 — This is consistent with a similar requirement in PRC-007-0, Requirement R2, that is assigned a lower VRF.
  - FERC's Guideline 4 — This requirement is assigned a lower VRF because it is a planning requirement that is administrative in nature. This requirement requires the Planning Coordinators to share their UFLS database with other Planning Coordinators. This is administrative and, if violated, would not adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. The assignment is consistent with the NERC definition of Lower VRF.

- FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement R8: Lower**
  - FERC's Guideline 2 — Not applicable – this requirement does not have sub-parts.
  - FERC's Guideline 3 — This is consistent with similar requirements in PRC-007-0, Requirements R2 and R3, that are assigned Lower VRFs.
  - FERC's Guideline 4 — This requirement is assigned a lower VRF because it is a planning requirement that is administrative in nature. The responsible entities are required to provide data to the Planning Coordinators to maintain the database. This is administrative and, if violated, would not adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. The assignment is consistent with the NERC definition of Lower VRF.
  - FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement R9: High**
  - FERC's Guideline 2 — Not applicable – this requirement does not have sub-parts.
  - FERC's Guideline 3 — A similar requirement in PRC-007-0, Requirement R1, is assigned a Medium VRF. As noted below in the discussion for Guideline 4 however, assignment of a High VRF for this requirement is consistent with the NERC definition of a High VRF.
  - FERC's Guideline 4 — The reliability objective of this requirement is for responsible entities to provide load tripping in accordance with the UFLS program design and schedule for application. This requirement is assigned a High VRF because violation of it, by failing to provide the load tripping required by the UFLS program design, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition. The assignment is consistent with the NERC definition of High VRF.
  - FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement R10: High**
  - FERC's Guideline 2 — Not applicable – this requirement does not have sub-parts.
  - FERC's Guideline 3 — Not applicable – this requirement is not related to similar reliability goals in other standards.

- FERC's Guideline 4 — The reliability objective of this requirement is that Transmission Owners provide automatic switching of Elements according to the UFLS program design. Similar to requirement R9, this requirement is assigned a High VRF because violation of it, by failing to provide automatic switching of Elements required by the UFLS program design, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition. The assignment is consistent with the NERC definition of High VRF.
- FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement 11: Medium**
  - FERC's Guideline 2 — This requirement has sub-parts, but these parts all support the parent requirement and do not have independent objectives.
  - FERC's Guideline 3 — This is consistent with a similar requirement in PRC-009-0, Requirement R1, that is assigned a Medium VRF.
  - FERC's Guideline 4 — A similar requirement exists in PRC-009-0 Requirement R1 and is assigned a Medium VRF. This requirement is assigned a Medium VRF because it requires assessment of UFLS equipment performance and UFLS program effectiveness during specified events involving UFLS activation that could identify deficiencies in either, and if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of the bulk electric system, or the ability to effectively control or restore the bulk electric system. The assignment is consistent with the NERC definition of Medium VRF.
  - FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement R12: Medium**
  - FERC's Guideline 2 — Not applicable – this requirement does not have sub-parts.
  - FERC's Guideline 3 — This is consistent with a similar requirement in PRC-009-0, Requirement R1, that is assigned a Medium VRF.
  - FERC's Guideline 4 — A similar requirement exists in PRC-009-0 Requirement R1 and is assigned a Medium VRF. This requirement is assigned a Medium VRF because it requires assessment of UFLS equipment performance and UFLS program effectiveness during specified events involving UFLS activation that could identify deficiencies in either, and if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of the bulk electric system, or the ability to

effectively control or restore the bulk electric system. The assignment is consistent with the NERC definition of Medium VRF.

- FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement R13: Medium**
  - FERC's Guideline 2 — Not applicable – this requirement does not have sub-parts.
  - FERC's Guideline 3 — This is consistent with a similar requirement in PRC-009-0, Requirement R1, that is assigned a Medium VRF.
  - FERC's Guideline 4 —This requirement is assigned a Medium VRF because it requires assessment of UFLS equipment performance and UFLS program effectiveness during specified events involving UFLS activation that could identify deficiencies in either, and if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of the bulk electric system, or the ability to effectively control or restore the bulk electric system. The assignment is consistent with the NERC definition of Medium VRF.
  - FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

- **VRF for PRC-006-1, Requirement R14: Lower**
  - FERC's Guideline 2 — Not applicable – this requirement does not have sub-parts.
  - FERC's Guideline 3 — This is consistent with a similar requirement in FAC-010-2, Requirement R5, that is assigned a Lower VRF.
  - FERC's Guideline 4 — This requirement is assigned a Lower VRF because it is administrative in nature and if violated would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. The assignment is consistent with the NERC definition of Lower VRF.
  - FERC's Guideline 5 — There is only one objective in this requirement and it is assigned an appropriate VRF.

The VRFs for the requirements in EOP-003-2 – Load Shedding Plans were not modified and remain the same as those proposed and approved for EOP-003-1.

Violation Severity Levels

The VSLs are presented below, followed by an analysis of whether the VSLs meet the

FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLS for PRC-006-1

Requirement R1	
Proposed Lower VSL	N/A
Proposed Moderate VSL	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
Proposed High VSL	The Planning Coordinator developed and documented criteria but failed to

	include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands
Proposed Severe VSL	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is currently no requirement like the requirement proposed in PRC-006-1. The VSL assignment does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Requirement R2	
Proposed Lower VSL	N/A

Proposed Moderate VSL	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2 or 2.3.
Proposed High VSL	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as [illegible]
Requirement R3	
Proposed Lower VSL	N/A
	2. OR 3. The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of parts an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Proposed Moderate VSL	The Planning Coordinator developed an UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.
Proposed High VSL	The Planning Coordinator developed an UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.
Proposed Severe VSL	The Planning Coordinator developed an UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of "Parts" of a requirement that an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance. PRC-006-0 Requirement R1 requires that the RRO develop a program. This requirement contains four sub-parts that align with separate requirements in the proposed standard. These separate requirements have their own VRF and set of VSLs for compliance. Requirement R1.1 in PRC-006-0 maps to R5, R7, and R13 in draft (3) PRC-006-1. Requirement R1.2 in PRC-006-0 maps to R3 in draft (3) PRC-006-1 Requirement R1.3 in PRC-006-0 maps to R6, R7, and R8 in draft (3) PRC-006-1. Requirement R1.4 in PRC-006-0 maps to R4, and R11.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be	The VSL aligns with the language of the requirement, and does not add to nor take away from it.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Requirement R4	
Proposed Lower VSL	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.
Proposed Moderate VSL	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.
Proposed High VSL	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.
Proposed Severe VSL	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of Parts of a Requirement that an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance. Failure to complete an assessment every five years was assigned a Level Four noncompliance in PRC-006-0, which is equivalent to a Severe VSL and is also assigned a

	Severe VSL in the draft (3) PRC-006-1.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Requirement R5	
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are not based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.
FERC VSL G2	The VSL is written as a pass/fail VSL and contains a Severe in compliance

Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	with guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Requirement R6	
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are not based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of	The VSL is written as a pass/fail VSL and contains a Severe in compliance with guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.

Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Requirement R7	
Proposed Lower VSL	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.
Proposed Moderate VSL	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.
Proposed High VSL	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.
Proposed Severe VSL	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.
FERC VSL G2 Violation Severity Level	The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.

Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Requirement R8	
Proposed Lower VSL	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
Proposed Moderate VSL	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
Proposed High VSL	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
Proposed Severe VSL	4. The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. 5. OR 6. The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.

FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Requirement R9	
Proposed Lower VSL	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
Proposed Moderate VSL	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
Proposed High VSL	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area

	in which it owns assets.
Proposed Severe VSL	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance. Requirement R1 of PRC-007 contains many requirements (in one) that our team has split out into independent requirements and therefore the comparison of VSLs is not a apples to apples comparison. The Lower VSL for Requirement R1 of PRC-007 says that the entity missed one or more of the RRO program requirements but was consistent with the amount of load shedding. Because our corresponding requirement (R10) focuses only on load shedding (the other RRO requirements map to other Requirements), adopting the load shedding part of the existing Lower for R1 of PRC-007 would not make sense because, it says that the load shedding requirement was met making it an invalid VSL for our purposes. We cannot write such a VSL. The other VSLs are consistent with the other levels (with the only exception being the Lower).PRC-007-0 R1 Moderate establishes a less than 95% of the regional requirement. PRC-007-0 R1 High establishes a less than 90% of the regional requirement and PRC-007-0 R1 Severe establishes a less than 85% of the regional requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of violations	The VSL is based on a single violation of the requirement.

Requirement R10	
Proposed Lower VSL	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
Proposed Moderate VSL	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which it owns transmission
Proposed High VSL	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
Proposed Severe VSL	The Transmission Owner provided less than 85% automatic switching of existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance. While there isn't an exact requirement in the current body of standards (this cannot be mapped to an existing requirement) a similar requirement PRC-007-0 Requirement R1 VSL's establish the same increments of load shedding as the proposed VSLs for this requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The VSL aligns with the language of the requirement, and does not add to nor take away from it.

Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Requirement R11	
Proposed Lower VSL	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.
Proposed Moderate VSL	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.
Proposed High VSL	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts 11.1 or 11.2.
Proposed Severe VSL	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the Parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in

	Requirement R11, Parts 11.1 and 11.2.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of parts an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Requirement R12	
Proposed Lower VSL	N/A
Proposed Moderate VSL	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.
Proposed High VSL	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.

Proposed Severe VSL	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of Parts of a Requirement that an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Requirement R13	
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

Proposed High VSL	N/A
Proposed Severe VSL	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are not based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL is written as a pass/fail VSL and contains a Severe in compliance with guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

Requirement R14	
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

Proposed High VSL	N/A
Proposed Severe VSL	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for the stated requirement are not based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL is written as a pass/fail VSL and contains a Severe in compliance with guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation of the requirement.

VSLs for EOP-003-2

The drafting team utilized the VSLs approved for EOP-003-1 in the VRF/VSL Order in June 2009 and made minor modifications to these VSLs to conform to the requirements. The

scope of the changes to the VSLs is minimal and reflects the edits to the Requirements intended to remove redundancies and potential conflicts with PRC-006-1. The modified VSLs can be found in **Exhibit A** to this filing.

V. Order No. 693 Directives Relative to new Requirements in PRC-006-1 and EOP-003-2

In FERC Order No. 693 paragraph 1480 addressing the determination on the proposed PRC-006-0 standard, the Commission stated:

> The Commission understands that UFLS, when properly coordinated with the dynamic response of the Bulk-Power System, is one of the safety nets that safeguards the system from cascading events, assuming it is properly coordinated with the dynamic response of the system. Until this Reliability Standard is submitted to the Commission for approval, we do not expect any lapse in the compliance with this Reliability Standard. As we stated in the NOPR, it is important that the existing regional reliability organizations continue to fulfill their current roles during this time of transition. The Commission expects that this function will pass from the regional reliability organization to the Regional Entity after they are approved.

In response to the expectation to transfer the UFLS function from the regional reliability organization to the Regional Entity, the standard drafting team chose an equally effective approach and assigned responsibility to design, assess, and coordinate the UFLS program to the Planning Coordinator. As explained above, the Planning Coordinators are the most appropriate entities to assign responsibility for the design, assessment, and coordination of the UFLS programs. As defined in version 5 of the Functional Model, the Planning Coordinator is "[t] he functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas". In addition, the Functional Model explains that "[w]hile the area under the purview of a Planning

Coordinator may include as few as one Transmission Planner and one Resource Planner, the Planning Coordinator's scope of activities may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities." Based on the definition of the role and based on existing practice, the Planning Coordinator is appropriately assigned the UFLS design, assessment and coordination activities. Because the Planning Coordinators do not generally have a region-wide view in their assessments, Requirements R2, subrequirement 2.3 is included to continue the present practice of coordinating UFLS systems on a regional basis. In addition, Requirements R5 and R13 require coordination among Planning Coordinators across Planning Coordinator boundaries and across Regional Entity boundaries within an interconnection when islands are identified through system studies or through system events that may cross Planning Coordinator or Regional Entity boundaries.

VI. SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

a. Development History

The drafting team developed these standards by following the NERC Reliability Standards development process. PRC-006-1 was publicly posted for comment on three occasions between 2008 and 2010 and EOP-003-2 was publicly posted for comment once in 2010. The standard drafting team considered comments from the industry and revised the standards and implementation plan accordingly. The Consideration of Comments documents are included in this filing as **Exhibit D.** The standards were posted for initial ballot in July, 2010, for two successive ballots in September and October, 2010, and for final recirculation ballot in October, 2010. A total of six drafts of the PRC-006-1 standard were developed and a total of four drafts of EOP-003-2 were developed.

During the first posting conducted July, 2008 through August, 2008, the standard drafting team received many comments on the proposed approach. The first posting proposed a common set of performance characteristics developed with the intent that each of the regional entities would be directed to develop a UFLS regional reliability standard that would fulfill the performance characteristics.

The standard drafting team's proposed approach of establishing common system performance characteristics rather than prescribing a uniform design specification for all UFLS programs within a continent-wide standard recognizes that, while the objective of the UFLS programs is always to arrest and recover frequency, a variety of design specifications could each be successful in accomplishing this. In addition, UFLS programs with differing design specifications can be successfully coordinated if they are designed to achieve the same system performance characteristics, even across interconnected regions. The drafting team reviewed the existing UFLS programs from each Region, and it became clear that various combinations of load steps and frequency set points exist and can achieve the objective of arresting and recovering frequency. It also became clear that there is not one best way to design a UFLS program. In light of these observations, the drafting team determined that most effective and efficient method to achieve the desired reliability goal is to establish common performance characteristics, because prescribing uniform UFLS program parameters would require most, if not all, entities to modify their UFLS equipment for little or no added reliability benefit. Industry comments were supportive of the approach of using common performance characteristics.

The drafting team also recognized the need to coordinate with the Project 2007-09 Generator Verification drafting team, specifically with regard to the proposed PRC-024-1

standard under development by that team. A mutual agreement on generator off-nominal frequency performance curves was reached between the two teams as well as an agreement that all Generator Owner applicability would be deferred to PRC-024-1 instead of including Generator Owner applicability in both standards. In conjunction with this coordination between drafting teams, the UFLS team resolved to address the issue of generators that do not conform to the standard off-nominal frequency performance curves by requiring that their trip characteristics be modeled in UFLS design assessments, and thus factored into the overall UFLS program design instead of requiring Generator Owners to arrange for compensatory load shedding for any non-conforming generators.

Based on stakeholder comments received from the first posting and the drafting team's consideration of those comments, the team converted the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard which, from that point on, followed the standards development process. While the majority of the comments indicated support for the creation of regional standards that determine the details of the UFLS programs, the majority of the comments also generally supported the concept of applying common continent-wide characteristics. The original intent was for the Regional Standards to meet these common performance characteristics. The creation of a continent-wide standard does not deviate from this approach but rather eliminates the confusion caused with this approach to direct the Regions to create Regional Reliability Standards for UFLS that met the common performance characteristics.

The team acknowledged that this was a shift in approach, but identified benefits to proceeding with a continent-wide standard. Among these identified benefits were the potential for better coordination between interconnected regions, development of the performance

characteristics within a formal standards development process, including a mechanism should there be a need for future revisions to the standard, and uniform requirements at the continent-wide level.

The standard drafting team has maintained the position that the creation of a continent-wide standard does not prohibit the creation of Regional Standards for UFLS. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as permitted by the NERC Rules of Procedure. This approach allows each region the option to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.

The team considered the role of the Planning Coordinators as the functional entity most suitable to determine the UFLS program design given that the Regional Entities are not users, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements. The second posting of the standard assigned the responsibility for designing the UFLS program to the Planning Coordinators. The Planning Coordinators within each region would define the parameters necessary to meet the performance characteristics in the continent-wide standard, such as the amount of load shedding required, how many blocks, and frequency set points and time delays (these specific parameters would not be contained in the proposed continent-wide-standard).

The standard drafting team recognized that UFLS programs typically have been developed within each Region by representatives from the vertically integrated utilities, Control Areas, and power pools, in that region. In order to continue to utilize that specific expertise within the regions, while recognizing that UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics, the standard drafting

team considered that the most appropriate entity to develop the UFLS programs based on function is the Planning Coordinator.

Therefore, the second draft of the proposed standard required that all Planning Coordinators within a Region work together as a group to develop the UFLS program for that Region that conforms to the performance characteristics contained in the proposed continent-wide standard and that the continent-wide standard would not specify how the regional programs are to be developed.

During the second posting conducted in April 2009 through May 2009, the standard drafting team thus assigned applicability to "groups" of Planning Coordinators rather than individual Planning Coordinators. The concept of groups of Planning Coordinators was intended to replicate historical practice where groups of entities within Regions were formed for the purpose of developing coordinated UFLS programs.

The applicability section of the second draft of the standard also included "Distribution Providers" and "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load." This second draft language reflected the standard drafting team's intent to establish the applicable entities in the UFLS standard to be those entities that provide UFLS capability. However, as a result of comments submitted in the second posting and further discussions within the standard drafting team, the standard drafting team concluded that the identification of the applicable entities was not an entirely accurate reflection of the participating registered entities. Therefore, the applicability section was modified in the third draft of the standard. The standard drafting team proposed that "UFLS entities" within the standard shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the

Planning Coordinators. Such entities may include Transmission Owners and/or Distribution Providers. The concept to define a group of entities within the body of the standard in the Applicability section currently exists in other Reliability Standards such as CIP-002-1.

In addition to Planning Coordinator and UFLS entity applicability, the standard drafting team included Transmission Owners that own certain Elements identified in the UFLS program established by the Planning Coordinators in the applicability section of the standard. Transmission Owners would be subject to the standard if they have been identified by the group of Planning Coordinators as having the obligation to switch certain Elements as part of the UFLS program.

In the second posting, many of the requirements were assigned to the groups of Planning Coordinators. These groups were to consist of all the Planning Coordinators within each of the Regional Entity areas. In the third draft of PRC-006-1, the standard drafting team revised these assignments to replace the groups with individual Planning Coordinators due to difficulties involved with enforcing responsibilities assigned to groups that do not currently exist.

Additionally in the third draft, the standard drafting team revised the under and overfrequency performance characteristics to refer to under and overfrequency curves (as Attachments 1 and 2) rather than discrete points as in former drafts. The curves provide more uniform coordination with generator under and overfrequency tripping requirements being proposed in PRC-024-1. In addition, the team extended the underfrequency performance characteristic curve to 60 seconds from the previous 30 second duration. The team agreed to extend the underfrequency performance characteristic to permit the Midwest Reliability Organization Regional Entity to avoid having to specify a variance to cover instances where there may be slower recovery of frequency. The standard drafting team concluded that recovery

of frequency within 60 seconds, though somewhat less stringent than requiring recovery within 30 seconds, remains acceptable for reliability and for coordination with generator underfrequency tripping. The standard drafting team similarly substituted the discrete points used in former drafts, for identifying which generator trip settings need to be included in the assessments of UFLS program design, with curves. These curves are shown on the same graphs as the performance characteristic curves (in Attachments 1 and 2) and are the same curves as are proposed in PRC-024-1 for generator under and overfrequency tripping, thus ensuring explicit coordination between UFLS and generator tripping.

Also in the third draft, due to the assignment of requirements to individual Planning Coordinators, the standard drafting team modified the approach for ensuring coordination within and between regions and for selecting islands that overlap adjacent regions within an interconnection.

The standard drafting team modified the approach for ensuring coordination with a region by revising the standard to require that each Regional Entity area be designated as an island for UFLS program design assessment purposes. While the individual Planning Coordinator UFLS program designs could be different, this amendment preserves coordination at the regional level.

The standard drafting team also modified the approach for ensuring coordination between regions. The drafting team deleted the requirement that involved the development of procedures for coordination between groups of Planning Coordinators in neighboring regions in selecting interregional islands (PRC-006-2, Requirement R4). This requirement was replaced with a new requirement that allows Planning Coordinators to select islands including interconnected portions of the bulk electric system in adjacent Planning Coordinator areas and Regional Entity areas, without the need for coordinating this selection with Planning Coordinators in neighboring

regions. While concurrence is not required for selecting islands, the Planning Coordinators are required to reach concurrence on the UFLS assessments for any islands identified by any Planning Coordinator that encompass more than one Planning Coordinator area.

Some commenters noted that switching of certain transmission facilities is sometimes necessary to be carried out as part of a UFLS program design. The standard drafting team agreed and added Requirement R10 in the third draft which requires Transmission Owners to provide automatic switching of Elements in accordance with the UFLS program design should a Planning Coordinator determine that such switching is a necessary part of the UFLS program design.

The standard drafting team added requirements in the third draft to assess the performance of UFLS programs "within one year of an actuation of UFLS resulting in a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program" (Requirement R11). Requirement R12 required the Planning Coordinator, in whose islanding event assessment (determined in Requirement R11) UFLS program deficiencies are identified, to conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation.

Requirement R13 required the Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, to reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment completion. In earlier drafts of the proposed standard, event analysis was left to be covered by the NERC Rules of Procedure. However, the drafting team determined that including a requirement in this standard for UFLS event analysis is

a more appropriate mapping of PRC-009-0 Requirement R1 which will be replaced by this standard, PRC-006-1.

During the posting timeframe, NPCC identified the need for a variance to the standard for the Québec Interconnection within NPCC. Due to the physical characteristics of the Québec system, the UFLS program in Québec arrests frequency at a lower threshold and permits higher frequency overshoot than allowed in the proposed standard. In response to this request for a variance, the team developed the variance to Requirement R3 Subrequirements 3.1 and 3.2 and Requirement R4 Subrequirements 4.1 through 4.6. The variance to these requirements reference separate underfrequency and overfrequency curves included as attachment 1A to the standard.

Finally, during the second posting, several commenters noted that certain requirements in the existing EOP-003-1 standard conflict with or are redundant with the requirements being proposed in PRC-006-1. The team agreed with these commenters and felt that if left unaddressed, the redundancies and conflicts could result in compliance issues in the future. As a result, the team submitted a request to supplement the existing SAR for Project 2007-01 to include a revision to EOP-003-1 in order to exclude those requirements related to automatic underfrequency load shedding since PRC-006-1 will contain these. The Standards Committee approved this action, and the team moved forward with revising the existing EOP-003-1 requirements. The team presented these modifications to the EOP-003-1 requirements in the third posting of the standard. Two other drafting teams are already in place to review the other aspects of EOP-003 as part of Project 2009-02—Real-time Tools and Project 2009-03 — Emergency Operations.

The proposed standard PRC-006-1 was posted a third time in June 2010 through July 2010 along with a first revision of EOP-003-2. Following this posting of PRC-006-1 and EOP-

003-2, the standard drafting team made several conforming changes as a result of industry comments received. The fourth version of the proposed standard addresses a coordination issue over which many commenters expressed concern. These commenters objected to the requirement for Planning Coordinators to reach concurrence with each other in R5 and R13 thus making one entity's compliance dependent on another entity. Some commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for obtaining concurrence among Planning Coordinators and other entities involved in UFLS planning and implementation. In the third version of the standard, Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than one Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer, the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable and that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team reaffirmed that the Planning Coordinator is the appropriate entity to identify islands, design UFLS programs, maintain UFLS data, and conduct assessments on UFLS program performance based on the definition of the Planning Coordinator in the Functional Model Version 5. Requirement R14 was added to provide a peer process by requiring the Planning Coordinators to respond to comments of Distribution Providers and Transmission Owners about the UFLS program design and implementation schedule.

Commenters expressed confusion over draft 3 of PRC-006-1 having Transmission Owners as possible UFLS Entities, but also separated out as Transmission Owners for Requirement R10 and suggested merging Requirements R9 and R10. The standard drafting team clarified that Requirement R9 pertains to automatic tripping of load and may be performed by

either the Distribution Provider or the Transmission Operator, and Requirement R10 pertains to switching of devices to control over-voltage that could occur as a result of underfrequency load shedding. It is possible that the Transmission Owners to which R10 applies may not have any responsibility for automatic tripping of load. Therefore, the team decided not to merge the two requirements.

Many commenters indicated that Generator Owners should be included in the applicability of the standard. Some suggested including a data requirement in PRC-006-1 that requires the Generator Owners to submit the necessary data for the purposes of the Requirement R4 UFLS design assessments. However, because such a data requirement already is proposed in PRC-024, the team clarified in the effective date of the standard that the parts of the requirement related to generators will not be effective until one year after PRC-024 is approved and effective. Adding such a data requirement to PRC-006 would be redundant, add unnecessary complexity, and possibly cause potential double violations of the standards.

A pre-ballot review of the PRC-006-1 and EOP-003-2 standards was conducted from June 11, 2010 through July 2, 2010 and an initial ballot and non-binding VRF/VSL poll was conducted from July 8, 2010 through July 17, 2010. The proposed standards and compliance elements did not receive weighted segment vote approval. The standard drafting team subsequently made substantive changes to the standard in preparation for a second ballot as permitted by the Standards Committee in order to address the comments received in the pre-ballot review and initial ballot. The changes made to PRC-006-1 at that time included modifications to the coordination requirements, Requirement R5 and Requirement R13, to remove the requirement for Planning Coordinators to achieve concurrence, the addition of R14 peer review of the UFLS program design and implementation schedule by UFLS entities,

modifications to the implementation plan, and other clarifying changes to the standard requirements. The standard drafting team made minor clarifying changes to EOP-003-2 to address industry comments that the standard should clearly state that some of the requirements exclude underfrequency load shedding and only address manual load shedding and under-voltage load shedding. A second ballot was conducted from July 24, 2010 through August 3, 2010.

The proposed standards and compliance elements did not receive weighted segment vote approval during the second ballot. Comments received during the second ballot expressed confusion over the actual application of the curves in the Attachment to the standard. Several commenters indicated that the graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves' data points. They suggested that a tabulation of the plotted curves break points should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under and overfrequency performance characteristic curve data points. The standard drafting team agreed with these commenters and modified the Attachments accordingly. The standard drafting team also clarified that the curves are solely for checking the frequency trajectories of simulations and not for setting UFLS relays.

Several commenters again expressed concern that the Applicability section of the standard, as proposed, excludes generators; however, Requirement R4 requires Planning Coordinators to model generator specific information. The suggestion to include the Generator Owners in the proposed standard would be problematic because Generator Owner data requirements already are proposed in the PRC-024-1 draft and are expected to remain in that proposed standard. The standard drafting team clarified in the effective date of PRC-006-1 that the sub-parts related to modeling of generator trip settings will not be effective until PRC-024 is

approved and effective. Adding a Generator Owner data requirement to PRC-006 would be redundant and cause double jeopardy concerns. It is the case that some standards are dependent on data requirements found in other standards. For example, the data necessary to comply with TPL standards is required under MOD standards

Many entities located in the Western Interconnection expressed concern that there was still a fundamental problem with the standard in that it did not specifically require the Planning Coordinators (PC) within an Interconnection to coordinate their plans among themselves. The standard drafting team worked with WECC to develop a proposed Variance to the continent-wide standard applicable to the Western Interconnection entities that addresses these concerns.

The standard drafting team made minor conforming changes to EOP-003-2 as requested by some commenters to further clarify that the standard excludes automatic underfrequency load shedding.

A successive ballot was conducted on September 24, 2010 through October 4, 2010. The proposed standards received an 81.72% weighted segment vote approval and achieved an 85.71% quorum. For the non-binding poll of VRFs and VSLs, 84% of those who registered to participate provided an opinion; 68% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed. Since at least one negative ballot included a comment, these results were not final and a final recirculation ballot was conducted. The recirculation ballot was conducted on October 18, 2010 through October 28, 2010. The proposed standards received an 84.67% weighted segment vote approval and achieved an 89.84% quorum. As a result, the ballot pool approved PRC-006-1 – Automatic Underfrequency Load Shedding and approved EOP-003-2 – Load Shedding Plans and the associated implementation plan; and approved retirement of the following four standards:

- PRC-006-0 – Development and Documentation of Regional UFLS Programs
- PRC-007-0 – Assuring Consistency of Entity Underfrequency Load Shedding Programs
- PRC-009-0 – Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event
- EOP-003-1 – Load Shedding Plans

VII. CONCLUSION

For the reasons stated above, NERC requests that FERC approve two proposed Reliability Standards, EOP-003-2 and PRC-006-1 as set out in **Exhibit A**, in accordance with Section 215(d)(1) of the FPA and Part 39.5 of FERC's regulations. NERC also requests that the implementation plans, as also set forth in **Exhibit B**, be approved as part of this filing and that the PRC-006-0**,** PRC-007-0, PRC-009-0**,** and EOP-003-1 standards be retired concurrent with implementation of EOP-003-2 and PRC-006-1. NERC requests that approvals be made effective in accordance with the effective date provisions set forth in the proposed Reliability Standards.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 31st day of March, 2011.

/s/ Holly A. Hawkins
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

Exhibit A — Reliability Standards Proposed for Approval

A. Introduction

1. Title: **Automatic Underfrequency Load Shedding**

2. Number: PRC-006-1

3. Purpose: To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. Applicability:

4.1. Planning Coordinators

4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

4.2.1 Transmission Owners

4.2.2 Distribution Providers

4.3 Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. (Proposed) Effective Date:

5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.

5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

B. Requirements

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

R3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: Medium][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection

within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those

of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per

Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking

- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.

E. Regional Variances

E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E.A.3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

EA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

EA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

EA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

E.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

E.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.E.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

M.E.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
EA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
EA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3

E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

E.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2.1. Those islands selected by applying the criteria in Requirement E.B.1, and

E.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

EB.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

E.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

E.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

E.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

E.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

E.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

E.B.11.1. The performance of the UFLS equipment,

E.B.11.2 The effectiveness of the UFLS program

E.B.12. Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.E.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.

M.E.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.

M.E.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.

M.E.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.

M.E.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.

M.E.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands
E.B.2	N/A	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				regional review to serve as a basis for designing its UFLS program.
E.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
E.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	through E.B.4.7.	through E.B.4.7.	through E.B.4.7.	through E.B.4.7. OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2
E.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.	assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.
E.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

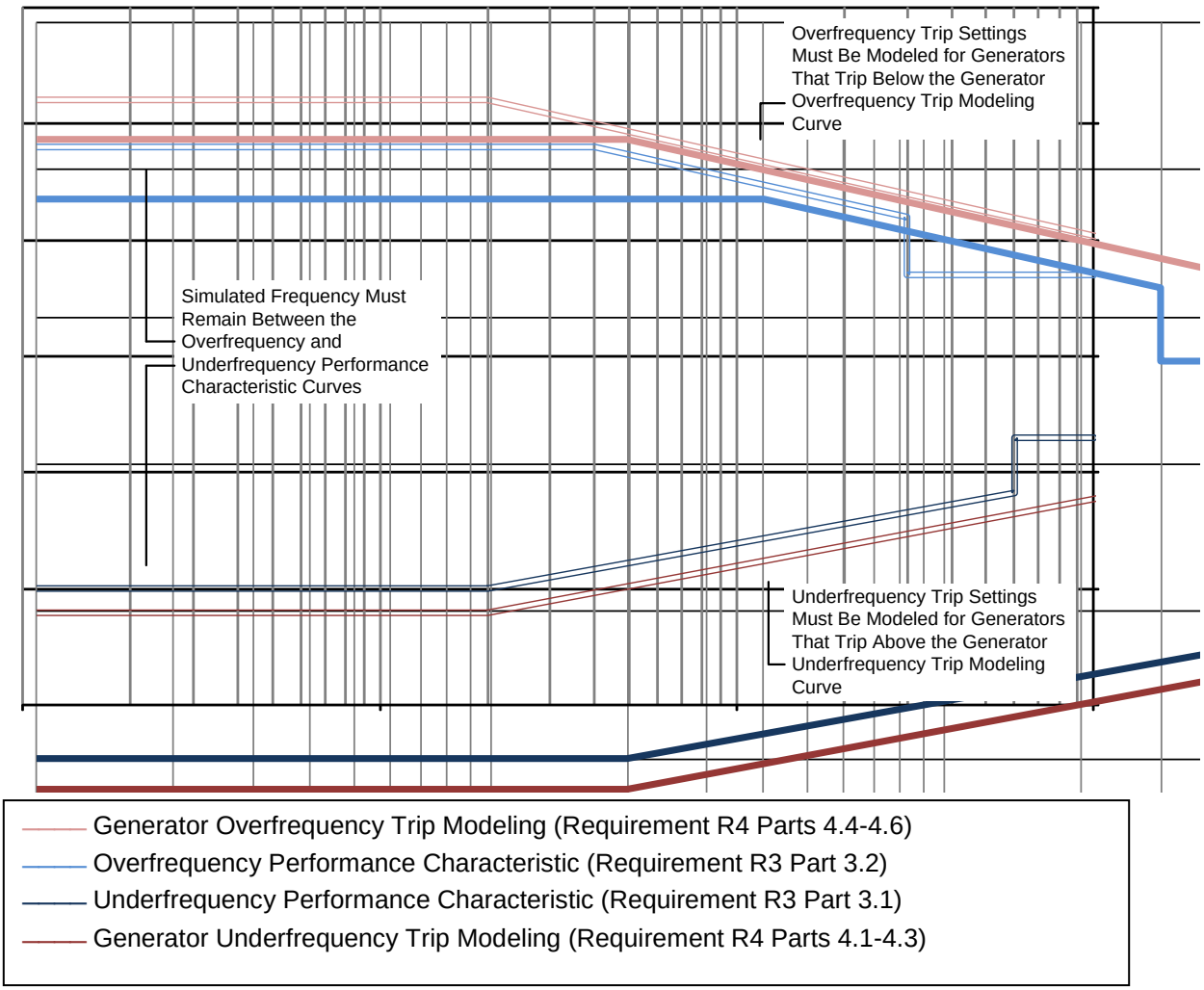
Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0	
1	November 4, 2010	Approved by the Board of Trustees	

PRC-006-1 – Attachment 1

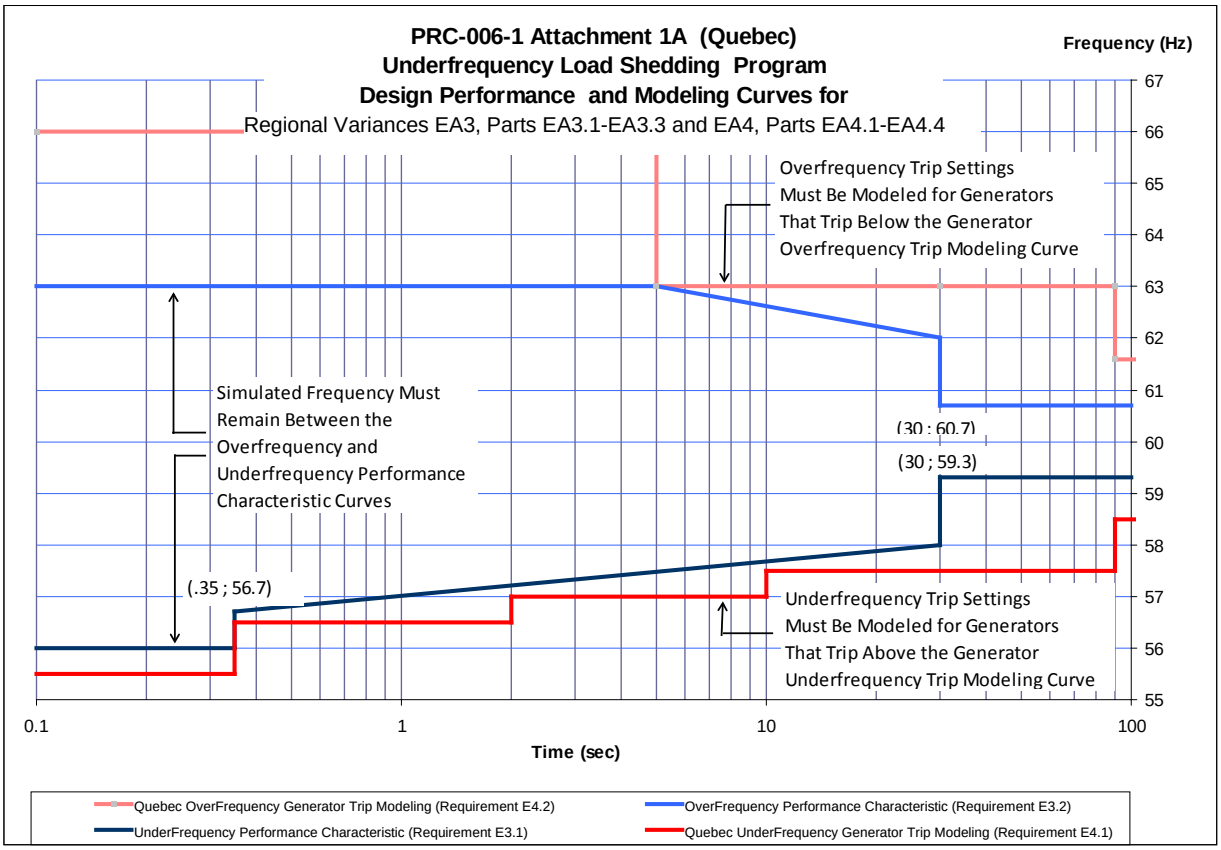
Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling		Underfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-1 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances EA3, Parts EA3.1-EA3.3 and EA4, Parts EA4.1-EA4.4
Frequency (Hz)
67
66
65
64
63
62
61
60
59
58
57
56
55
Overfrequency Trip Settings
Must Be Modeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(30 ; 60.7)
(30 ; 59.3)
(.35 ; 56.7)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip Modeling Curve
0.1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement E4.2)
OverFrequency Performance Characteristic (Requirement E3.2)
UnderFrequency Performance Characteristic (Requirement E3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement E4.1)

A. Introduction

1. **Title:** ~~**Development and Documentation of Regional Reliability Organizations'**~~ **Automatic Underfrequency Load Shedding** ~~**Programs**~~

2. **Number:** PRC-006-~~0~~1

3. **Purpose:** ~~Provide~~ To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures ~~by implementing an Under Frequency Load Shedding (UFLS) program.~~.

4. **Applicability:**

   ~~**4.1.** Regional Reliability Organization~~

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.3 Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **(Proposed) Effective Date:** ~~April 1, 2005~~

   5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.

   5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

B. Requirements

~~**R1.** Each Regional Reliability Organization shall develop, coordinate, and document an UFLS program, which shall include the following:~~

~~**1.1.** Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations.~~

~~**1.2.** Design details shall include, but are not limited to:~~

~~**1.2.1.** Frequency set points.~~

~~**1.2.2.** Size of corresponding load shedding blocks (% of connected loads.)~~

~~**1.2.3.** Intentional and total tripping time delays.~~

~~1.2.4. Generation protection.~~

~~1.2.5. Tie tripping schemes.~~

~~1.2.6. Islanding schemes.~~

~~1.2.7. Automatic load restoration schemes.~~

~~1.2.8. Any other schemes that are part of or impact the UFLS programs.~~

~~1.3. A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.~~

~~1.4. Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to:~~

~~1.4.1. A review of the frequency set points and timing, and~~

~~1.4.2. Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation.~~

~~R2. The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).~~

~~R3. The Regional Reliability Organization shall provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days).~~

~~Measures~~

~~M1. The Regional Reliability Organization shall have documentation of the UFLS program and current UFLS database.~~

~~M2. The Regional Reliability Organization shall have evidence it provided documentation of its UFLS program and its database information to NERC as specified in Reliability Standard PRC-006-0_R2.~~

~~M3. The Regional Reliability Organization shall have evidence it provided documentation of its assessment of its UFLS program to NERC as specified in Reliability Standard PRC-006-0_R3.~~

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

R3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: Medium][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS

program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments

of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or

- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~Compliance Monitor: NERC.~~

~~**1.2. Compliance Monitoring Period and Reset Timeframe**~~

~~On request (within 30 calendar days) for the program, database, and results of assessments.~~

Regional Entity

~~1.3.~~1.2. **Data Retention**

~~None specified.~~

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

~~None.~~

~~2. Levels of Non-Compliance~~

~~**2.1. Level 1:** Documentation demonstrating the coordination of the Regional Reliability Organization's UFLS program was incomplete in one of the elements in Reliability Standard PRC-006-0_R1.~~

~~**2.2. Level 2:**~~ Not applicable.

~~**2.3. Level 3:** Not applicable.~~

~~**2.4. Level 4:** Documentation demonstrating the coordination of the Regional Reliability Organization's UFLS program was incomplete in two or more requirements or documentation demonstrating the coordination of the Regional Reliability Organization's UFLS program was not provided, or an assessment was not completed in the last five years.~~

~~Regional Differences~~

~~3. None identified.~~

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.

R #		Lower VSL	Moderate VSL	High VSL	Severe VSL
R3		N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area
R4		The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS

R #		Lower VSL	Moderate VSL	High VSL	Severe VSL
					assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2
R5		N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6		N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7		The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.

R #		Lower VSL	Moderate VSL	High VSL	Severe VSL
R8		The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9		The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
R10		The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.

E. Regional Variances

E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E.A.3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

EA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

EA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

EA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

E.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

E.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.E.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

M.E.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
EA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
EA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3

E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

E.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2.1. Those islands selected by applying the criteria in Requirement E.B.1, and

E.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

EB.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

E.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

E.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

E.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

E.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

E.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

E.B.11.1. The performance of the UFLS equipment,

E.B.11.2 The effectiveness of the UFLS program

E.B.12. Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.E.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.

M.E.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.

M.E.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.

M.E.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.

M.E.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.

M.E.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands
E.B.2	N/A	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				regional review to serve as a basis for designing its UFLS program.
E.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
E.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	through E.B.4.7.	through E.B.4.7.	through E.B.4.7.	through E.B.4.7. OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2
E.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event

E #		Lower VSL	Moderate VSL	High VSL	Severe VSL
				documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.	assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.
E.B.12		N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.

E #		Lower VSL	Moderate VSL	High VSL	Severe VSL
					OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

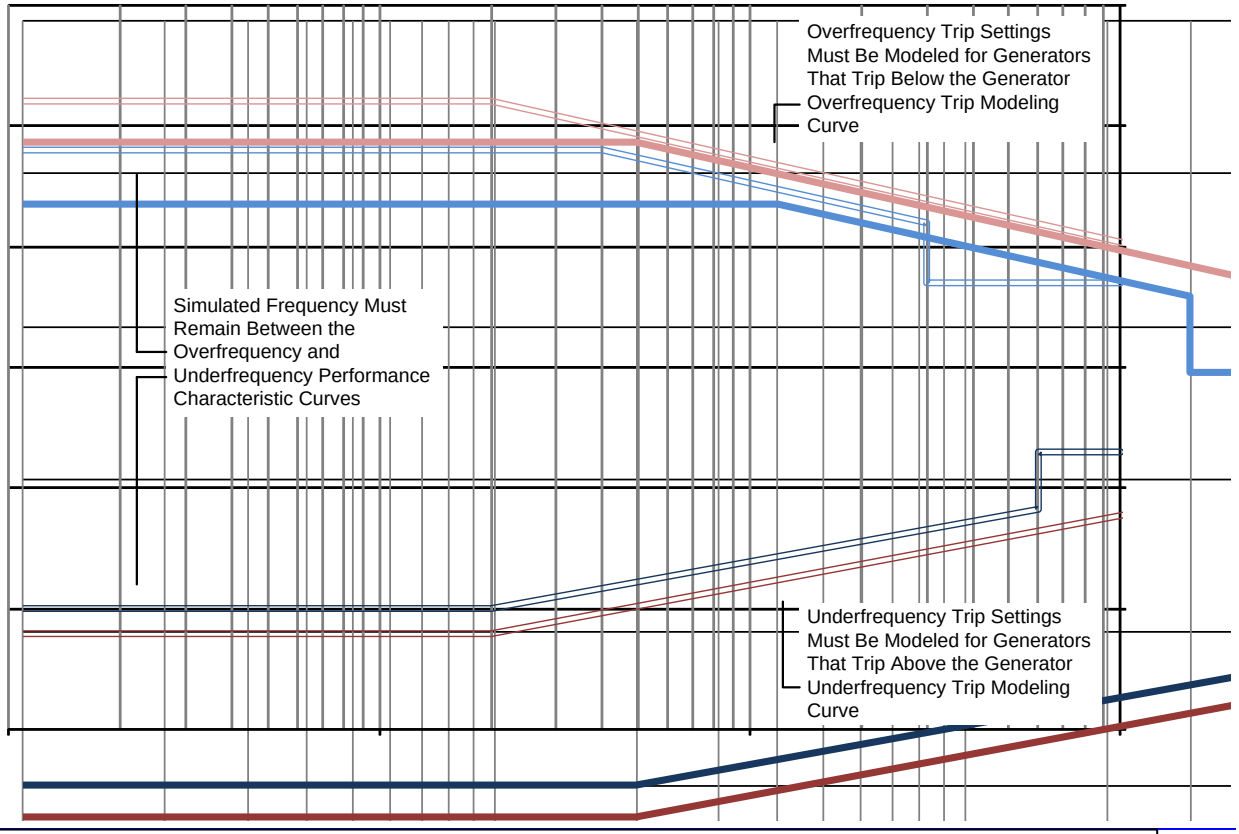
Associated Documents

Version History

Version	Date	Action	Change Tracking
~~0~~1	~~April 1, 2005~~	~~Effective Date~~Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0	~~New~~
1	November 4, 2010	Approved by the Board of Trustees	

PRC-006-1 – Attachment 1

Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6

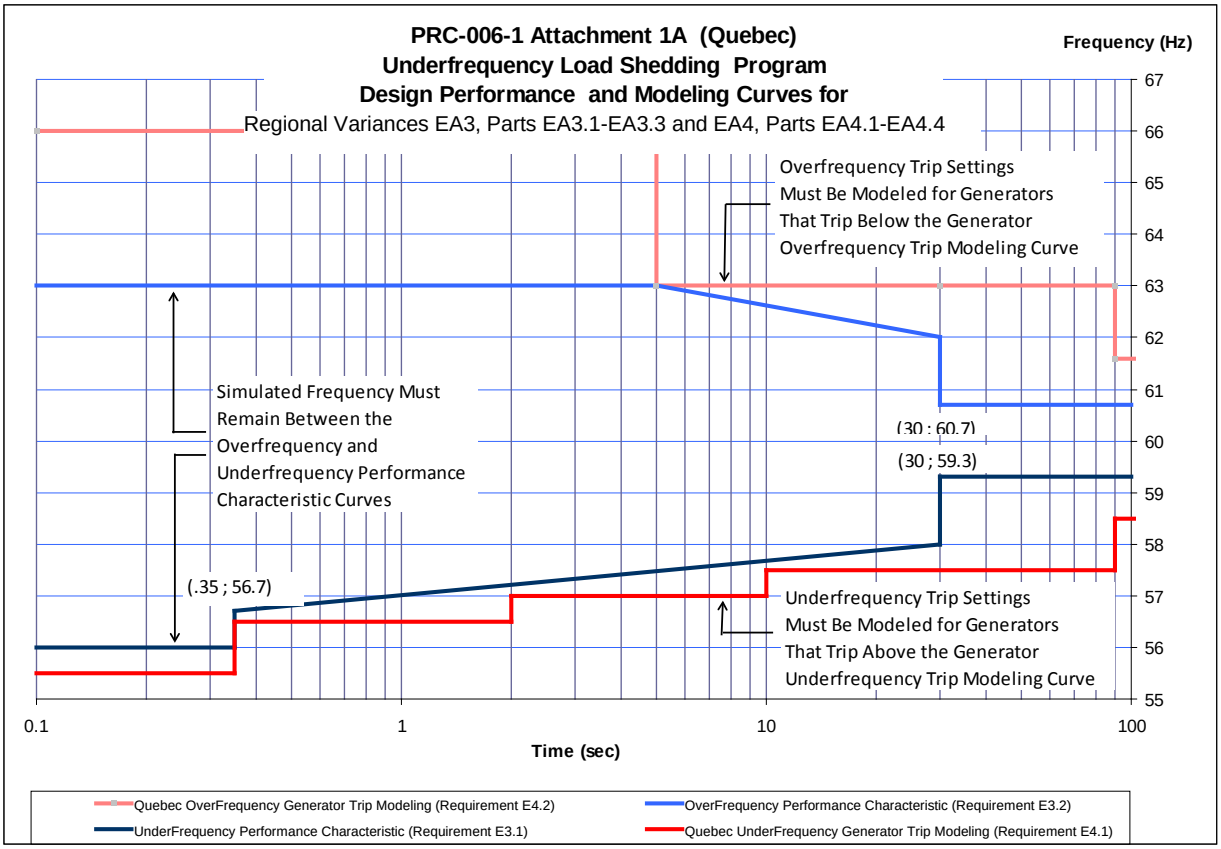


Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling		Underfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s

f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-1 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances EA3, Parts EA3.1-EA3.3 and EA4, Parts EA4.1-EA4.4
Frequency (Hz)
67
66
65
64
63
62
61
60
59
58
57
56
55
Overfrequency Trip Settings
Must Be Modeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(30 ; 60.7)
(30 ; 59.3)
(.35 ; 56.7)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip Modeling Curve
0.1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement E4.2)
OverFrequency Performance Characteristic (Requirement E3.2)
UnderFrequency Performance Characteristic (Requirement E3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement E4.1)

A. Introduction

1. Title: **Load Shedding Plans**

2. Number: EOP-003-2

3. Purpose: A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. Applicability:

4.1. Transmission Operators.

4.2. Balancing Authorities.

5. Effective Date: One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions

R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

Approved by the Board of Trustees on November 4, 2010

C. Measures

M1. Each Transmission Operator that has or directs the deployment of undervoltage load shedding facilities, shall have and provide upon request, its automatic load shedding plans. (Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
R2	N/A	N/A	N/A	The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.
R3.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
R4.	N/A	N/A	N/A	The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.
R5.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
R7.	The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.
R8.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

E. **Regional Differences**

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 4, 2010	Modified R4, R5, R6 and associated VSLs for R2, R4, and R7to clarify that the requirements don't apply to automatic underfrequency load shedding. Approved by the Board of Trustees.	Revised to eliminate redundancies with PRC-006-1

A. Introduction

1. Title: **Load Shedding Plans**

2. Number: EOP-003-~~1~~2

3. Purpose: A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. Applicability:

4.1. Transmission Operators.

4.2. Balancing Authorities.

~~**5. Effective Date:** January 1, 2007~~

5. Effective Date: One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator ~~and Balancing Authority~~ shall establish plans for automatic load shedding for ~~underfrequency or~~ undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator ~~or Balancing Authority~~ shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: ~~frequency, rate of frequency decay,~~ voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator ~~and Balancing Authority~~ shall coordinate automatic undervoltage load shedding throughout their areas with ~~underfrequency isolation of generating units,~~ tripping of shunt capacitors, and other automatic actions that will occur under abnormal ~~frequency,~~ voltage, or power flow conditions~~.~~

Approved by the Board of Trustees~~:~~ on ~~November 1, 2006~~ November 4, 2010
~~Effective Date: January 1, 2007~~

R8. Each Transmission Operator or Balancing Authority shall have plans for operator ~~-~~controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

M1. Each Transmission Operator ~~and Balancing Authority~~ that has or directs the deployment of undervoltage ~~and/or underfrequency~~ load shedding facilities, shall have and provide upon request, its automatic load shedding plans~~.(~~. (Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring ~~and Reset Time Frame~~

One or more of the following methods will be used to assess compliance:

- ~~-~~ Self-certification (Conducted annually with submission according to schedule.)
- ~~-~~ Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- ~~-~~ Periodic Audit (Conducted once every three years according to schedule.)
- ~~-~~ Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor~~;~~.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None~~.~~

2. **Violation Severity Levels ~~of Non-Compliance:~~**

~~**2.1. Level 1:** Not applicable.~~

~~**2.2. Level 2:** Not applicable.~~

~~**2.3. Level 3:** Not Applicable.~~

~~**2.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**2.4.1** Does not have an automatic load shedding plan as specified in R2.~~

~~**2.4.2** Does not have manual load shedding plans as specified in R8.~~

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
R2	N/A	N/A	N/A	The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.
R3.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
R4.	N/A	N/A	N/A	The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				flow levels) listed in the requirement.
R5.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.
R6.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
R7.	The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.
R8.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				shedding, as directed by the requirement.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 4, 2010	Modified R4, R5, R6 and associated VSLs for R2, R4, and R7to clarify that the requirements don't apply to automatic underfrequency load shedding. Approved by the Board of Trustees.	Revised to eliminate redundancies with PRC-006-1

Exhibit B — Implementation Plans Proposed for Approval

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for Underfrequency Load Shedding Project

Standards Involved

- PRC-006-1 Underfrequency Load Shedding
- EOP-003-2 – Load Shedding Plans
- PRC-006-0 — Development and Documentation of Regional UFLS Programs
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements
- PRC-009-0 — UFLS Performance Following an Underfrequency Event

Prerequisite Approvals

With one exception, there are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Under Frequency Load Shedding standard and any associated regional reliability standards can be implemented. Parts 4.1 through 4.6 of Requirement R4 of the Under Frequency Load Shedding standard shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

Proposed Effective Date

Compliance with the new version PRC-006-1 — Underfrequency Load Shedding reliability standard (Requirements R1 through R14 with the exception noted above for Requirement R4, Parts 4.1 through 4.6) is effective one year following the first day of the first calendar quarter after applicable regulatory approvals.

The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time: 1) to develop, modify, or validate (to determine that the program meets performance characteristics) existing UFLS programs, and 2) to establish a schedule for implementation, or validate a schedule for completion of program revisions already in progress. Transmission Owners and Distribution Providers shall comply with the schedule determined by the Planning Coordinator but no sooner than the effective date of the standard.

Compliance with the revised EOP-003-2 — Load Shedding Plans reliability standard is effective one year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

Applicability

Certain requirements within the proposed standard are intended to apply only to entities that own or operate UFLS relays. These requirements would not apply to other entities. The drafting team has designated these entities that own or operate UFLS relays as “UFLS Entities.” They may include the following:

- Transmission Owners
- Distribution Providers

For decades underfrequency load shedding programs have been implemented by different entities depending on how the transmission system was constructed and owned. In some parts of the country, Distribution Providers accomplished this task, in others it was the Transmission Owners. Indeed, the set of standards intended to be replaced by this new standard allowed either of these registered entities, along with others in some cases, to accomplish the task of owning and operating UFLS relays. Because of this historical nature of the entities involved in the implementation of UFLS programs, and as listed in the applicability listed in the standards PRC-007-0 and PRC-009-0 that this standard is intended to replace, each of the functions listed above will have a role in implementing UFLS programs.

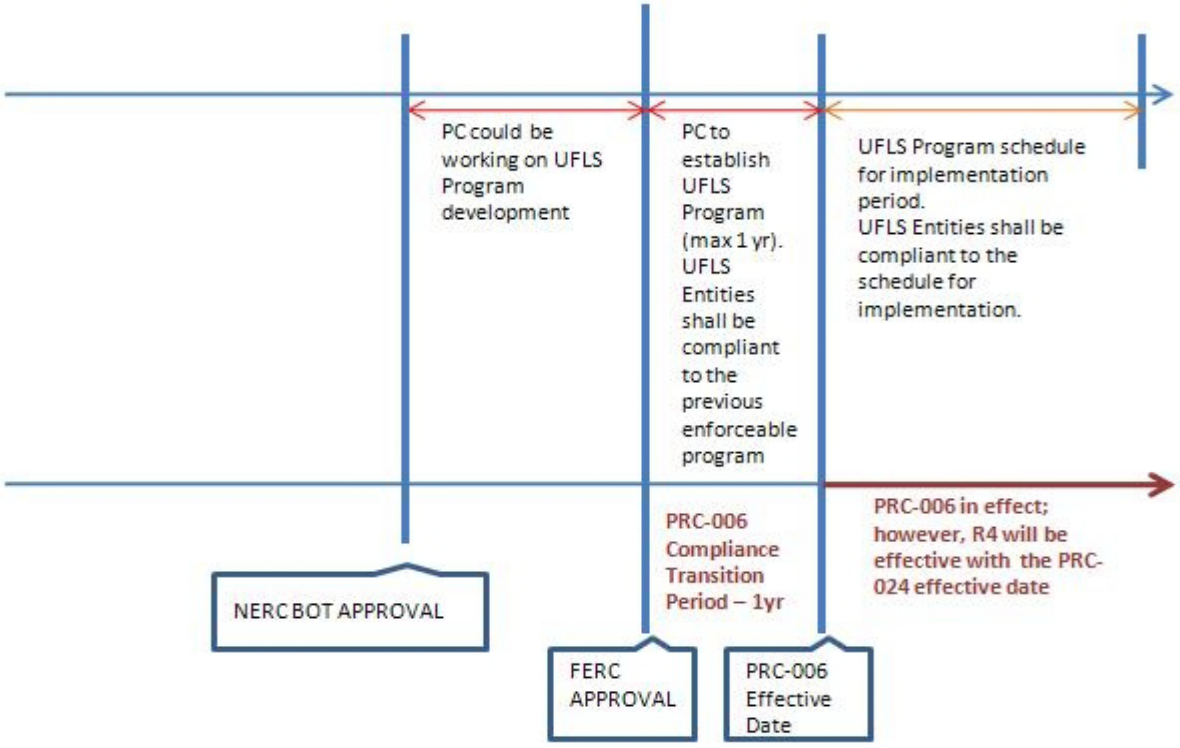
Retired Standards

The following standards will be retired when PRC-006-1 becomes effective:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-009-0 — UFLS Performance Following an Underfrequency Event will be completely retired once PRC-006-1 becomes effective as specified above.

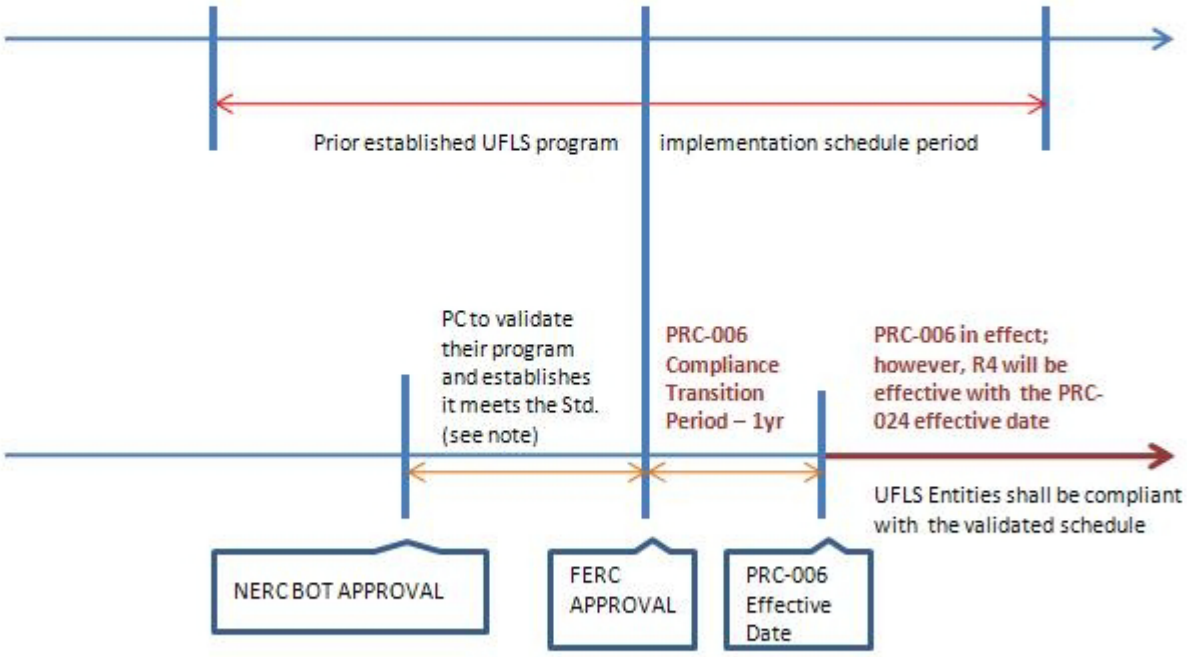
UFLS Timeline Example 1

(No Existing program)



UFLS Timeline Example 2

(Existing UFLS program)



Note: If the PC determines that their program is not valid to the standard, PC will need to follow Timeline Example 1.

Exhibit C — Mapping of Existing Requirements to New Requirements

PRC 006-0, PRC 007-0, and PRC 009-0 Mapping to
Proposed Continent-Wide Standard PRC-006-1

PRC-006-0: Development and Documentation of Regional UFLS Programs

Requirement in the Existing PRC Standards	Location in Proposed Continent-Wide UFLS Standard	Requirement in Proposed Continent Wide UFLS Standard PRC-006-1	Needed for Reliability
R1: Each Regional Reliability Organization shall develop, coordinate, and document an UFLS program, which shall include the following:	Continent-wide Standard Requirements R3	**R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). **3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and **3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and **3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following: **3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES **3.3.2.** Generating plants/facilities greater than	Yes

		75 MVA (gross aggregate nameplate rating) directly connected to the BES **3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.	
R1.1: Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations.	Continent-wide Standard Requirement R5 and R13	**R5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: • Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or • Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or • Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO. **R13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency	Yes

		excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: • Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or • Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or • Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.	
R1.2 Design details shall include, but are not limited to: **R.1.2.1: Frequency set points.**	Continent-wide Standard Requirement R3	**R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). **3.1.** Frequency shall remain above the Underfrequency	Yes
R.1.2.2: Size of corresponding load shedding blocks (% of connected loads.)			Yes

R.1.2.3: Intentional and total tripping time delays.		Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and **3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and **3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following: **3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES **3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES **3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.	Yes
R.1.2.4: Generation protection.	Continent-wide Standard Requirement R3, part 3.3 and Requirement R4, Parts 4.1-4.6	**3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following: **3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly	Yes

		connected to the BES **3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES **3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. **R4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: **4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1. **4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1. **4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1. **4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1. **4.5.** Overfrequency trip settings of generating	

		plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1. **4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.	
R.1.2.5: Tie tripping schemes.	Continent-wide Standard Requirement R2 part 2.2	**2.2.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and	Yes
R.1.2.6: Islanding schemes.			Yes
R.1.2.7: Automatic load restoration schemes.	Continent-wide Standard Requirement R4 part 4.7	**R4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: **4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.	Yes
R.1.2.8: Any other schemes that are part of or impact the UFLS programs	Continent-wide Standard Requirement R10	**R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	Yes

R1.3: A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.	Continent-wide Standard Requirements R6, R7, and R8.	**R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. **R7.** Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. **R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	Yes
R1.4: Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to: **R1.4.1: A review of the frequency set points and timing, and** **R1.4.2: Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation.**	Continent-wide Standard Requirement R4 and R12.	**R4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: **4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1. **4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1. **4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator	Yes

		Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1. **4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1. **4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1. **4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1. **4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment. **R12.** Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation.	
R2: The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).	These existing requirements are covered in the NERC Rules of Procedures, Section 401.3: Data Access — All bulk power system owners, operators, and users shall provide to NERC and the applicable regional entity such information as is		No

	necessary to monitor compliance with the reliability standards. NERC and the applicable regional entity will define the data retention and reporting requirements in the reliability standards and compliance reporting procedures.		
R3: The Regional Reliability Organization shall provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days).	These existing requirements are covered in the NERC Rules of Procedures, Section 401.3: Data Access — All bulk power system owners, operators, and users shall provide to NERC and the applicable regional entity such information as is necessary to monitor compliance with the reliability standards. NERC and the applicable regional entity will define the data retention and reporting requirements in the reliability standards and compliance reporting procedures.		No

PRC-007: Assuring Consistency with Regional UFLS Program Requirements

Requirement in the Existing PRC Standards	Location in Proposed Continent-Wide UFLS Standard PRC-006-1		Needed for Reliability
R1: The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.	Continent-wide Standard Requirements R9 and R10.	**R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. **R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	Yes
R2: The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.	Continent-wide Standard Requirement R8.	**R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	Yes
R3: The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).	Continent-wide Standard Requirement R8.	**R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	Yes

PRC-009: UFLS Performance Following an Underfrequency Event

Requirement in the Existing PRC Standards	Location in Proposed Continent-Wide UFLS Standard PRC-006-1		Needed for Reliability
R1: The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:	Continent-wide Standard Requirement R11	**R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: **11.1.** The performance of the UFLS equipment, **11.2.** The effectiveness of the UFLS program.	Yes
R1.1: A description of the event including initiating conditions.	Continent-wide Standard Requirement R11 (although R1.1 is not explicitly covered)	**R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: **11.1.** The performance of the UFLS equipment, **11.2.** The effectiveness of the UFLS program.	No
R1.2: A review of the UFLS set points	Continent-wide Standard Requirement R11 (covered	**R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency	Yes

and tripping times.	under 11.1 and 11.2)	excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: **11.1.** The performance of the UFLS equipment, **11.2.** The effectiveness of the UFLS program.	
R1.3: A simulation of the event.	Continent-wide Standard Requirement R11	**R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: **11.1.** The performance of the UFLS equipment, **11.2.** The effectiveness of the UFLS program.	Yes
R1.4: A summary of the findings.	Continent-wide Standard Requirement R11 (R1.4 not explicitly covered in R11)	**R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: **11.1.** The performance of the UFLS equipment, **11.2.** The effectiveness of the UFLS program.	No
R2: The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability	These existing requirements are covered in the NERC Rules of Procedures, Section 401.3: Data Access — All bulk power system owners, operators, and users shall		Yes

Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.	provide to NERC and the applicable regional entity such information as is necessary to monitor compliance with the reliability standards. NERC and the applicable regional entity will define the data retention and reporting requirements in the reliability standards and compliance reporting procedures.		

Exhibit D — Consideration of Comments Documents

Consideration of Comments on Underfrequency Load Shedding Characteristics

The Underfrequency Load Shedding Standard Drafting Team thanks all commenters who submitted comments on the UFLS Characteristics document. This document was posted for a 45-day public comment period from July 2, 2008 through August 15, 2008. The stakeholders were asked to provide feedback on the document through a special Electronic Standard Comment Form. There were 38 sets of comments, including comments from more than 100 different people from approximately 100 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Based on stakeholder comments and the drafting team's consideration of those comments, the team has converted the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will refine the proposed standard following the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

The SDT made the following clarifications when converting the UFLS Reliability Standard Characteristics into proposed requirements:

- The responsibility for designing UFLS programs is assigned to groups of Planning Coordinators – each group of Planning Coordinators is expected to work cooperatively with other Planning Coordinators. (R1–R8)
- It is necessary to identify island(s) as a basis for designing the UFLS program, but not necessary to identify every possible island. Analysis to determine islands does not need to predict how island boundaries might form in future events. The SDT modified the criteria for identifying islands. (R3, R4, R5)
- The UFLS system must be designed such that frequency does not drop bellow 58.0 Hz for an imbalance up to and including 25% (rather than "of at least 25%") — for an imbalance exceeding 25%, Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program - the imbalance = (load – actual generation output)/ (load) of up to 25 percent within the identified island – the intent is that this would work for any load level (peak, off-peak, etc.). The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. (R6)
- The cumulative limits apply for each simulated event; not cumulatively for all actual system events. The standard does not require measuring compliance for actual events against the standard. (R6.2)
- Revised the performance characteristics (Requirement R6.2) from 59.5 Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics.
- Revised the performance characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate

with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).

- Modified the performance characteristic in R6.4 to specify where to measure voltages during simulated events.
- Added a requirement (R7.3) in the proposed continent-wide standard to require modeling of automatic load restoration in the five year assessments performed by the group of Planning Coordinators in each region.
- Revised the performance characteristic (Requirement R8) to require annual updates of the database. The SDT also removed the annual certification noting this obligation is effectively addressed by Requirements R9 (annual database updates) and R10 (provide load tripping in accordance with the UFLS program design). The measures by which compliance with these Requirements will be assessed will be defined in the Measures section of the proposed standard.

There were several minority issues that were not resolved when the characteristics were translated into requirements, including the following:

- A preference for a set of Regional Standards in support of continent-wide characteristics, but not a continent-wide standard. The SDT believes that the continent-wide standard will eliminate the confusion caused with the originally proposed requirements that were intended to direct the Regions to create Regional Reliability Standards for UFLS that met the common performance characteristics. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.
- Concern that the performance characteristics may be too specific to accommodate the needs of every region or they may be too extreme for some regions. The SDT feels that the performance characteristics set forth in the proposed continent wide standard are intended to ensure coordination among the programs that Planning Coordinators are required to design.
- Recommendation to revise the performance characteristic from 58.4 Hz to 59.4 Hz for up to nine minutes and continuous above 59.4 Hz. The suggested settings do not coordinate with generator under-frequency time durations allowed by manufacturers.
- Recommendation to specify a minimum size of the postulated island that is of sufficient size to affect the Bulk Electric System and have frequency overshoot requirements for the entire Eastern Interconnection as well as for smaller identified islands. The SDT believes that the UFLS programs must be designed such that all interconnected systems will meet common performance characteristics. Common performance characteristics facilitate coordination between regions. An island could be subject to other performance characteristics in addition to the common performance characteristics for imbalances greater than 25% if the Regional Entities develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.
- Recommendation to establish a common format for the database. The SDT believes that a variety of formats could serve reliability equally well and as such the SDT does not feel compelled to specify a format in the proposed continent-wide standard. The group of Planning Coordinators in each region has been assigned the responsibility for assessments of the UFLS program in the proposed continent-wide standard and is therefore best suited to identify the program database format.

- Recommendation to allow "analytical studies" instead of "dynamic simulations" to verify the UFLS program design. The SDT believes it is not possible to verify the adequacy of the implementation of the regional UFLS program in achieving the performance characteristics without some sort of dynamic simulation and has decided to retain this level of specificity.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
	Individual	Karl Kohlrus	City Water, Light & Power - Springfield, IL	1 - Transmission Owners, 3 - Load-serving Entities, 5 - Electric Generators
	Group	Guy Zito	NPCC	10 - Regional Reliability Organizations/Regional Entities

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Thompson	Consolidated Edison Co. of New York, Inc.	NPCC	1
2.	David Kiguel	Hydro One Networks Inc.	NPCC	1
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Frederick White	Northeast Utilities	NPCC	1
5.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
6.	Ron Falsetti	Independent Electricity System Operator	NPCC	2
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Randy MacDonald	New Brunswick System Operator	NPCC	2
9.	Gregory Campoli	New York Independent System Operator	NPCC	2

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)	
10.	Michael Ranalli		National Grid	NPCC	3
11.	Ronald E. Hart		Dominion Resources, Inc.	NPCC	5
12.	Ralph Rufrano		New York Power Authority	NPCC	5
13.	Brian L. Gooder		Ontario Power Generation Incorporated	NPCC	5
14.	Michael Gildea		Constellation Energy	NPCC	6
15.	Brian D. Evans-Mongeon		Utility Services	NPCC	6
16.	Donald E. Nelson		Massachusetts Dept. of Public Utilities	NPCC	9
17.	Brian Hogue		NPCC	NPCC	10
18.	Alan Adamson		New York State Reliability Council	NPCC	10
19.	Guy Zito		NPCC	NPCC	10
20.	Lee Pedowicz		NPCC	NPCC	10
21.	Gerry Dunbar		NPCC	NPCC	10
	Individual	Edwin Averill	Grand River Dam Authority	5 - Electric Generators, 1 - Transmission Owners, 9 - Federal, State, Provincial Regulatory, or other Government Entities	
	Group	Ken McIntyre	ERCOT	2 - RTOs and ISOs	
	Individual	Don McInnis	Florida Power & Light	1 - Transmission Owners	
	Individual	Vic. Baerg	Manitoba Hydro	1 - Transmission Owners, 5 - Electric Generators, 3 - Load-serving Entities, 9 - Federal, State, Provincial Regulatory, or other Government Entities, 6 - Electricity Brokers, Aggregators	
	Individual	Thad Ness	American Electric Power (AEP)	6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners	

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
	Group	Annette Bannon	PPL Generation	1 - Transmission Owners, 5 - Electric Generators, 6 - Electricity Brokers, Aggregators

Additional Member	Additional Organization	Region	Segment Selection	
1.	Mark Heimbach	PPL EnergyPlus	MRO	6
2.			NPCC	6
3.			RFC	6
4.			SERC	6
5.			SPP	6
6.	John Cummings	PPL EnergyPlus	WECC	6
7.	Joe Kisela	PPL Generation	RFC	5
8.			NPCC	5
9.	Tom Lehman	PPL Montana	WECC	5
10.	Dave Gladey	PPL Susquehanna	RFC	5
11.	Mike DeCesaris	PPL Electric Utilities	RFC	1
12.	Gabe Laczo	PPL Electric Utilities	RFC	1
13.	Gary Bast	PPL Electric Utilities	RFC	1
14.	Dave Price	PPL Electric Utilities	RFC	1

	Group	Lynn Schroeder	Southwest Power Pool (SPP UFLS Standard Drafting Team)	10 - Regional Reliability Organizations/Regional Entities
	Group	Brian Bartos	Bandera Electric Cooperative (TRE Regional UFLS Standard Drafting Team)	1 - Transmission Owners

Additional Member	Additional Organization	Region	Segment Selection	
1.	Dennis Kunkel	AEP	ERCOT	1
2.	Randy Jones	Calpine	ERCOT	5
3.	Matt Pawlowski	FPL Energy	ERCOT	5

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
4.		Rayborn Reader	EPCO	ERCOT 7
5.		Eddy Reece	Rayburn Country	ERCOT 1
6.		Barry Kremling	GVEC	ERCOT 1
7.		Sergio Garza	LCRA	ERCOT 1
8.		Steve Myers	ERCOT ISO	ERCOT 2
9.		Ken McIntryre	ERCOT ISO	ERCOT 2
	Individual	O. J. Brouillette	Louisiana Generating, LLC	3 - Load-serving Entities, 5 - Electric Generators, 4 - Transmission-dependent Utilities, 1 - Transmission Owners
	Individual	Steve Harmath	Orrville Utilities	4 - Transmission-dependent Utilities
	Group	Marie Knox	Midwest ISO	2 - RTOs and ISOs

Additional Member	Additional Organization	Region	Segment Selection
1.	Kirit Shah	Ameren	SERC 1
2.	Jim Cyrulewski	JDRJC Associates	RFC 8

	Group	Jim Busbin	Southern Company Services, Inc	5 - Electric Generators, 1 - Transmission Owners

Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Wilson	Southern Company Services	SERC 1
2.	Terry Coggins	Southern Company Services	SERC 1
3.	Jonathan Glidewell	Southern Company Services	SERC 1
4.	Raymond Vice	Southern Company Services	SERC 1
5.	J. T. Wood	Southern Company Services	SERC 1
6.	Terry Crawley	Southern Company Services	SERC 5
7.	Marc Butts	Southern Company Services	SERC 1

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
	Individual	Mark Kuras	PJM	2 - RTOs and ISOs
	Group	Peter Heidrich	Florida Reliability Coordinating Council	1 - Transmission Owners, 4 - Transmission-dependent Utilities, 3 - Load-serving Entities, 10 - Regional Reliability Organizations/Regional Entities, 5 - Electric Generators

Additional Member	Additional Organization	Region	Segment Selection	
1.	Jerry Murphy	Reedy Creek Improvement District	FRCC	3
2.	John Shaffer	Florida Power & Light	FRCC	1
3.	John Odom	FRCC	FRCC	10
4.	Fabio Rodriguez	Progress Energy	FRCC	1
5.	Don GIlbert	JEA	FRCC	5
6.	Alan Gale	City of Tallahassee	FRCC	5
7.	Don McInnis	Florida Power & Light	FRCC	1
8.	Art Nordlinger	Tampa Electric Company	FRCC	1
9.	FRCC System Protection & Control Subcommittee	FRCC	FRCC	10

	Group	Bob Jones	Southern Company Services, Inc. - Trans	1 - Transmission Owners

Additional Member	Additional Organization	Region	Segment Selection	
1.	Rick Foster	Ameren	SERC	1
2.	Anthony Williams	Duke Energy Carolinas	SERC	1
3.	Greg Davis	Georgia Transmission Corp.	SERC	1
4.	Ernesto Paon	Municipal Electric Authority of Georgia	SERC	1
5.	Andrew Fusco	NC Municipal Power Agency #1	SERC	1
6.	John O'Connor	Progress Energy Carolinas	SERC	1
7.	Pat Huntley	SERC Reliability Corp.	SERC	10
8.	Jonathan Glidewell	Southern Company Services, Inc. - Trans	SERC	1

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
9.		Tom Cain	Tennessee Valley Authority	SERC 1
	Individual	Kevin Koloini	Buckeye Power, Inc.	3 - Load-serving Entities, 4 - Transmission-dependent Utilities, 5 - Electric Generators
	Individual	Rick White	Northeast Utilities	1 - Transmission Owners
	Individual	Howard Rulf	We Energies	5 - Electric Generators, 4 - Transmission-dependent Utilities, 3 - Load-serving Entities
	Individual	John W Shaffer	Florida Power & Light Co.	1 - Transmission Owners
	Individual	Eric Mortenson	Exelon	1 - Transmission Owners, 3 - Load-serving Entities
	Individual	D. Bryan Guy	Progress Energy Carolinas, Inc.	3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners
	Individual	Kirit Shah	Ameren	6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 1 - Transmission Owners
	Group	Ken Goldsmith (MRO NERC Standards Review Subcommittee)	Alliant Energy	4 - Transmission-dependent Utilities

Additional Member	Additional Organization	Region	Segment Selection	
1.	Neal Balu	WPS	MRO	3, 4, 5, 6
2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Jim Haigh	WAPA	MRO	1, 6
5.	Tom Mielnik	MEC	MRO	1, 3, 5, 6
6.	Pam Sordet	Xcel	MRO	1, 3, 5, 6
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Eric Ruskamp	LES	MRO	1, 3, 5, 6

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
9.		Joseph Knight	GRE	MRO	1, 3, 5, 6
10.		Joe DePoorter	MGE	MRO	3, 4, 5, 6
11.		Larry Brusseau	MRO	MRO	10
12.		Michael Brytowski	MRO	MRO	10
	Group	Brent Ingebrigtson	E.ON U.S.	6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners
	Individual	Kris Manchur	Manitoba Hydro	5 - Electric Generators, 6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 1 - Transmission Owners
	Group	Sandra Shaffer	PacifiCorp	1 - Transmission Owners, 5 - Electric Generators, 3 - Load-serving Entities

Additional Member	Additional Organization	Region	Segment Selection	
1.	Mike Viles	Transmission Technical Operations	WECC	1
2.	Kelly Johnson	Transmission Customer Service Engineering	WECC	1
3.	Terry Doern	Transmission Technical Operations	WECC	1
4.	Gregory Vasallo	Transmission Customer Service Engineering	WECC	1
5.	Stephen Hitchens	Transmission Technical Operations	WECC	1
6.	Rebecca Berdahl	Power Long Term Sales and Purchases	WECC	3

	Group	Denise Koehn	Transmission Reliability Program	3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners, 6 - Electricity Brokers, Aggregators
	Individual	Ron Falsetti	Independent Electricity System Operator	2 - RTOs and ISOs
	Individual	Wayne Kemper	CenterPoint Energy	1 - Transmission Owners
	Group	Sam Ciccone	FirstEnergy Corp.	1 - Transmission Owners, 5 - Electric Generators, 3 - Load-serving Entities, 6 - Electricity Brokers, Aggregators

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)

Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FirstEnergy	RFC	1, 3, 5, 6
2.	Dave Folk	FirstEnergy	RFC	1, 3, 5, 6
3.	Art Buanno	FirstEnergy	RFC	1
4.	Jim Detweiler	FirstEnergy	RFC	1
5.	Bob McFeaters	FirstEnergy	RFC	1
6.	Ken Dresner	FirstEnergy	RFC	5
7.	Bill Duge	FirstEnergy	RFC	5

	Group	Jason Shaver	American Transmission Company	1 - Transmission Owners
	Individual	Scott Berry	Indiana Municipal Power Agency	4 - Transmission-dependent Utilities
	Individual	Greg Rowland	Duke Energy	5 - Electric Generators, 6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 1 - Transmission Owners
	Group	Greg Davis	Georgia Transmission Corporation	1 - Transmission Owners
	Individual	Greg Ward / Darryl Curtis	Oncor Electric Delivery	1 - Transmission Owners
	Individual	Ed Davis	Entergy	
	Group	Robert Rhodes	Southwest Power Pool	1 - Transmission Owners, 2 - RTOs and ISOs, 3 - Load-serving Entities, 4 - Transmission-dependent Utilities, 5 - Electric Generators

Additional Member	Additional Organization	Region	Segment Selection	
1.	Bill Bateman	East Texas Electric Coop.	SPP	3, 4
2.	John Boshears	City Utilities of Springfield	SPP	1, 3, 5
3.	Brian Berkstresser	Empire District Electric	SPP	1, 3, 5

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)	
4.		Mike Gammon	Kansas City Power & Light	SPP	1, 3, 5
5.		Don Hargrove	Oklahoma Gas & Electric	SPP	1, 3, 5
6.		Danny McDaniel	CLECO	SPP	1, 3, 5
7.		Kyle McMenamin	Southwestern Public Service Company	SPP	1, 3, 5
8.		Eddy Reece	Rayburn Country Electric Coop	SPP	3, 4
9.		Robert Rhodes	Southwest Power Pool	SPP	2

1. The SDT determined that there is no need to have a continent-wide standard, and proposes that all UFLS requirements be contained within the regional UFLS standards developed in accordance with the Characteristics of UFLS Regional Reliability Standards. The SDT developed a set of characteristics which each of the regional entities will be directed to include in its UFLS regional reliability standard. The SDT developed these characteristics in an attempt to direct the regional entities to develop requirements based on system performance, without prescribing specifics of how to meet the specified performance. Do you agree with the drafting team?

Summary Consideration:

The Underfrequency Load Shedding Drafting team reviewed comments for this question and has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a proposed continent wide standard that will follow the standards development process. The team acknowledges that this is a shift in approach but sees many benefits to proceeding with a continent-wide standard.

1. While the majority of the comments indicated support for the creation of Regional Standards that determine the details of the UFLS programs the majority of the comments also generally supported the concept of applying common continent-wide characteristics. The Regional Standards would have to meet these common performance characteristics. The creation of a continent-wide standard does not deviate from this approach but rather eliminates the confusion caused with this new form of requirement that was intended to direct the Regions to create Regional Reliability Standards for UFLS that met the common performance characteristics.
2. The creation of a continent-wide standard does not prohibit the creation of Regional Standards for UFLS. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. This approach still allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
3. Several commenters expressed concern that the approach set forth in the first posting (the directive to the Regions containing the performance characteristics) was "a new kind of requirement listing [that] circumvents the Standard Development Procedure". Further, commenters expressed concern that this approach creates a "new class of Standards [that] creates confusion" namely that is unclear how the characteristics would be revised in the future and the role stakeholders would play in future revisions. The SDT agrees with these comments and feels that by creating a continent wide standard containing the performance characteristics these concerns will be addressed leaving the more detailed requirements (if needed) to a Regional Standard or Regional Variance as outlined in the NERC Rules of Procedure.
4. Several commenters indicated that they thought it appropriate that the Regions develop the details of the UFLS program such as the total amount to load shed; how many blocks at what frequency, etc. The SDT clarifies that the performance characteristics are intended to ensure coordination among the programs. In the proposed continent-wide standard the SDT assigned the responsibility of designing the UFLS program to the Planning Coordinator (Requirement R2). The Planning Coordinators within a region will define the amount of load shed required, how many blocks, at what frequency, etc. (these specific requirements are not contained in the proposed continent wide standard).
5. Several commenters indicated that the performance characteristics may be too specific to accommodate the needs of every region or they may be too extreme for some regions. The SDT feels that the performance characteristics set forth in the proposed continent wide standard are intended to ensure coordination among the programs that Planning Coordinators are required to design. For an imbalance up to and

including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

6. Several commenters asked the SDT to clarify if their intent is to withdraw PRC-006-0, PRC-007-0 and PRC-009-0 when applicable regional replacement standards are established and become effective. In addition, the commenters interpreted that the SDT directive approach was a means for NERC to require the Regions to develop appropriate Regional standards that share continent-wide characteristics because NERC standards cannot be applied to Regional Entities. The SDT recognizes that NERC standards should not be applicable to Regional Entities and confirms that this was the original intent of the "UFLS Regional Reliability Standard Characteristics"; however, the SDT decided to convert the directive into a continent wide standard as a means for NERC to require shared continent wide characteristics applicable to Planning Coordinators, Transmission Owners, and Distribution Providers. The proposed continent wide standard would replace PRC-006-0, PRC-007-0, and PRC-009-0 once it is approved and becomes effective.

Organization	Question 1:	Question 1 Comments:
PJM	No	UFLS should be used as a safety net, based on installation requirements rather than performance requirements. As it is currently worded, if your UFLS load shedding does not arrest a blackout, you could potentially be found non-compliant.
Response: The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6).		
Exelon	No	This document, 'Characteristics of UFLS Regional Reliability Standards' is not a NERC Standard, yet it contains requirements for adherence by parties other than NERC or a Region. This new kind of requirement listing circumvents the Standard Development Procedure. It is not clear how this could ever be revised or what role stakeholders have in this. The creation of a new class of Standards creates confusion and is contrary to the well developed process that has been established. Why couldn't this be a NERC Standard, with all of the recognized checks and balances provided with that process, while at the same time leaving the few requirements that really need to be 'fill in the blank' up to a more detailed Regional Standard?
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
Oncor Electric Delivery	No	Oncor Electric Delivery does not believe that this document should be issued at this time. Many of the proposed design characteristics are based on parameters contained in the proposed NERC Reliability Standard PRC-024 which is still in the development stage. This document should be reissued for comments once PRC-024 has been approved.
Response: The SDT agrees that performance characteristics should be based on the proposed generator under-frequency time durations in PRC-024. In addition, the SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team (GV SDT)by providing the underfrequency performance curve to ensure that		

Organization	Question 1:	Question 1 Comments:
the performance characteristics do not conflict with the generator off nominal frequency capability curve. The SDT will continue to coordinate with the GV SDT and we believe it does not matter whether PRC-006 or PRC-024 is approved first as long as this coordination exists.		
Southwest Power Pool	No	We have concerns that in eliminating the continent-wide standard we are also eliminating continent-wide enforcement and the common denominator that NERC provides through the reliability standards. Under the proposal, enforcement would apparently fall to each regional entity which could lead to inconsistency across an interconnection.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
CenterPoint Energy	No	CenterPoint Energy believes this document has been issued for comments prematurely and recommends this effort be postponed until the proposed NERC Reliability Standard PRC-024 (Generator Protective System Performance During Frequency and Voltage Excursions) has been fully developed and vetted by all stakeholders through the NERC process. The prescriptive technical design characteristics proposed in these Characteristics of UFLS Regional Reliability Standards are based on parameters contained in the proposed PRC-024 that have not yet been issued to the industry for comments. It is premature to base these Characteristics on another standard that is still in the development process. **Response:** The SDT agrees that performance characteristics should be based on the proposed generator under-frequency time durations in PRC-024. In addition, the SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team (GV SDT) by providing the underfrequency performance curve to ensure that the performance characteristics do not conflict with the generator off nominal frequency capability curve. The SDT will continue to coordinate with the GV SDT and we believe it does not matter whether PRC-006 or PRC-024 is approved first as long as this coordination exists. As an alternative to postponing this effort, the proposed prescriptive technical characteristics could be deleted. While CenterPoint Energy proposes less restrictive characteristics in response to Questions 2, 3, and 4 below, our recommendation is that they be deleted or that Project 2007-1 be postponed. All the proposed technical design parameters appear to apply only for "underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent". This characterization is simplistic and does not address all UFLS needs for other system conditions that can occur. The imbalance and response to an imbalance can vary dramatically considering not only the amount of generation that's on-line, but also the type of generation on-line. System response will depend upon governor response and system inertia. For example, in order to arrest frequency decay for a 25% load / generation imbalance within prescribed parameters under certain conditions, a region may have to employ aggressive load shedding that might cause an overshoot beyond prescribed parameters under other conditions. This is especially true for regions that have significant penetration of wind energy, where system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions. The open ended requirement for arresting frequency after an initial imbalance of at least 25% could be interpreted to encompass imbalances of 50%, 75% or even

Organization	Question 1:	Question 1 Comments:
		100% which is infeasible. **Response:** The SDT agrees that the system off nominal frequency performance is a function of many factors and that simulation modeling assumptions can vary widely. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. Compliance with performance characteristics when the imbalance is greater than 25 % is not required by this standard. The SDT believes that proposed performance characteristics values are achievable for generator deficits up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.
PPL Generation	Yes and No	PPL Corporation agrees with the SDT that a continent-wide standard is not practical and having the regional entities develop a process and appropriate requirements consistent with the "Characteristics of UFLS Regional Reliability Standards" is the most effective way to ensure a reliable transmission system. We also agree it is necessary for the standard to establish specific limits. However, rigid adherence to the stated characteristics may not be possible for certain generating facilities because of equipment limitations or manufacturer recommended over/under frequency protection requirements. Such limitations or requirements can not be ignored. As such, provisions to deviate from stated characteristics in these instances must be included in any regional entity standard developed. The expectation is that the generator would provide documentation as to why a specific characteristic can not be met and the regional entity would review the issue and determine if mis-coordination with the UFLS program exists. If mis-coordination does exist, the regional entity, with input from the host TO/TSP and the generator, would then be responsible for appropriate mitigation measures (i.e. shedding of additional load).
Response: The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: “To ensure that generators will not trip off-line during specified voltage and frequency excursions.” The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.		
Ameren	Yes and No	We agree that there is no need for a continent-wide UFLS standard. However, numerous system conditions would need to be studied to identify potential islands (Characteristic #2), and we doubt that the analyses to be performed would often accurately predict how the system would separate with any certainty. Also, it is likely that any separation would not be along company or regional lines. Therefore, we suggest that each region involve and coordinate neighboring regions in these studies and in the development of the regional UFLS standard and its requirements.
Response: The SDT agrees that analysis to determine islands would not necessarily predict how island boundaries would form in real events. However, it is necessary to identify island(s) as a basis for designing the UFLS program (Requirement R5). Assessment of islands that overlap regional boundaries requires coordination between adjacent regions. The intent of characteristic 3 (Requirement R4) is to ensure		

Organization	Question 1:	Question 1 Comments:
that Planning Coordinators have procedures in place to carry out required coordination.		
Midwest ISO	Yes and No	We agree with the drafting team's approach in developing a set of system characteristics rather than a continent wide standard. We are concerned though that when standards PRC-006, PRC-007, and PRC-009 are replaced that information and requirements could be lost that are important to UFLS. Regional standards drafting teams should review the content of these existing standards to determine what should be transferred to their standards. We believe that the characteristics are a good starting point and should set a minimum level of performance expected. The drafting team should consider whether there are any special systems (such as a peninsula) that may warrant different criteria and allow the regional standards to consider other criteria for those systems. To better assess the quality of the characteristics, the drafting team should provide the history behind these characteristics. Where did they come from? How were they derived? Did they come from old regional reliability organization (from MAIN, MAPP, ECAR, etc) criteria?
Response: The SDT team developed a mapping document (included in the Implementation Plan) to ensure that requirements would not be lost. This may address the concerns regarding losing requirements in the merging of the three standards. The SDT notes that the requirements that were not included in the proposed characteristics are currently included in the NERC ERO Rules of Procedure (Appendix 8 – NERC Blackout and Disturbance Response Procedures). If the commenter feels (after reviewing the mapping) that the SDT has left out requirements please inform the SDT. The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. Regarding the history for the performance characteristics, the technical basis for the performance characteristics was developed through a review of relevant industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. The SDT included more details regarding the technical justification for the performance characteristics in the comment form background (including specific IEEE standards). In addition, the SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team by providing the underfrequency performance curve to ensure that the performance characteristics do not conflict with the generator off nominal frequency capability curve.		
Alliant Energy	Yes and No	The MRO believes that the Regions should determine the details of the UFLS. We believe the regions are best situated to perform the studies and determine the total amount of load shed required, how many blocks, at what frequency, etc. This includes setting regional performance objectives for UFLS design, and deciding on generator under/over frequency minimum time delays and frequency setpoints. **Response:** The SDT has decided to convert the “Characteristics of UFLS Regional Reliability Standards” into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. The Planning Coordinators within a region will define the amount of load shed required, how many

Organization	Question 1:	Question 1 Comments:
		blocks, at what frequency, etc. Generator under/over frequency minimum time delays and frequency setpoints are covered under PRC-024 Generator Verification. The MRO believes that the Under Frequency Load Shedding Standard Drafting Team is headed in the right direction as far as allowing the regions to create their own UFLS program within continental wide characteristics. It's the MRO's contention that while the 11 general characteristics are reasonable they may be too specific to accommodate the needs of every region or they may be too extreme for every region. The MRO asks that the UFLS SDT allow the regions a reasonable amount of time to determine the specific number which would accommodate the general NERC objectives but would address regional conditions. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. There are some inconsistencies in the document as the Characteristics listed in the "UFLS Regional Reliability Standard Characteristics" document do not match with those listed in this comment form in the "Characteristics of UFLS Regional Reliability Standards" section. Specifically, 1) What is the technical justification for the frequency overshoot limit of 61 Hz? (third bullet) 2) What is the technical justification for the time durations for the Volts/Hz? (Fourth Bullet) **Response:** Performance characteristic 4.4 (Requirement R6.4) states that: Control voltage during and following UFLS operations such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than two seconds cumulatively per simulated event, and does not exceed 1.10 for longer than 45 seconds cumulatively per simulated event. The comment form does not reflect the characteristic but should have. This was an oversight. Regarding the justification for the Volts/Hz performance characteristic, the technical basis for this performance characteristic was developed through a review of relevant industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. The SDT included more details regarding the technical justification for the performance characteristics in the comment form background (including specific IEEE standards). The MRO interprets that the STD is proposing the withdrawal of the PRC-006-0, PRC-007-0, and PRC-009-0 standards when applicable Regional replacement standard(s) are established and become effective. The MRO also interprets that the STD is proposing UFLS Regional Reliability Standard Characteristics, rather than revising the NERC UFLS

Organization	Question 1:	Question 1 Comments:
		standards, because NERC standards cannot be applicable to Regional Entities and the Characterizes may be a means for NERC to require the Regions to develop appropriate Regional standards that share key continent-wide characteristics. **Response:** The SDT recognizes that NERC standards should not be applicable to Regional Entities and confirms that this was the original intent of the "UFLS Regional Reliability Standard Characteristics"; however, the SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard as a means for NERC to require shared continent-wide characteristics. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The MRO agrees that the existing NERC standards could be replaced with appropriate Regional standards and believe that some UFLS program requirements should be different in different Regions. The MRO disagrees that the Characteristics should direct Regional Entities to be based on continent-wide system performance values. Appropriate system performance levels and appropriate percentage of load shedding will vary for each potential island and depend on the composition of load, generation, and system protection within the island. The continent-wide Characteristics should deal with such broader issues such as: identification of potential islands, coordination among accountable entities, identification of appropriate load shedding percentage, identification and coordination with island-specific generation-related limits and system protection settings, responsibility for UFLS program design and implementation, responsibility for and frequency of UFLS program assessment, etc. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. The Planning Coordinators within a region will define the amount of load shed required, how many blocks, at what frequency, etc. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.
FirstEnergy Corp.	Yes and No	We agree with the SDT that there is no need for NERC to develop a continent-wide standard since there is already much work being done in some regions already creating their own regional standard. And we agree that NERC should at least specify the minimum expectations of UFLS programs needed by each region so that there is continent-wide consistency in the creation and implementation of regional UFLS standards. However, it is not clear how this document will be maintained in the NERC reliability standards realm. This document does not appear to have a standard number and version so that it can be maintained and used as a living document to be used as a reference for the minimum regional requirements. We are concerned that after these minimum regional characteristics are vetted through industry and subsequently used by the regions to create their initial versions of their region's UFLS standard, they will not be transparent to the regions years from now when they revise their standards. Additionally, at some point NERC and industry may determine the need to add and/or revise these minimum regional characteristics due to ever changing

Organization	Question 1:	Question 1 Comments:
		industry technology or methodologies regarding UFLS equipment design and utilization.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
American Transmission Company	Yes and No	ATC interprets that the STD is proposing the withdrawal of the PRC-006-0, PRC-007-0, and PRC-009-0 standards when applicable Regional replacement standard(s) are established and become effective. ATC also interprets that the STD is proposing UFLS Regional Reliability Standard Characteristics, rather than revising the NERC UFLS standards, because NERC standards can not be applied to Regional Entities and the Characteristics may be a means for NERC to require the Regions to develop appropriate Regional standards that share key continent-wide characteristics. **Response:** The SDT recognizes that NERC standards should not be applicable to Regional Entities and confirms that this was the original intent of the "UFLS Regional Reliability Standard Characteristics"; however, the SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard as a means for NERC to require shared continent-wide characteristics. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. We agree that the existing NERC standards could be replaced with appropriate Regional standards and believe that some UFLS program requirements should to be different in different Regions. ATC disagrees that the Characteristics should direct Regional Entities to be based on continent-wide system performance values. Appropriate system performance values and appropriate percentage of load shedding will vary for each potential island and depend on the nature of load, generators, protection schemes, and dispatch within each island. The continent-wide Characteristics should deal with such broader issues such as: identification of potential islands, coordination among accountable entities, identification of appropriate load shedding percentage, identification and coordination with island-specific generation-related limits and system protection settings, responsibility for UFLS program design and implementation, , responsibility for and frequency of UFLS program assessment, the factors to be considered in assessments, etc. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. The Planning Coordinators within a region will define the amount of load shed required, how many blocks, at what frequency, etc. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

Organization	Question 1:	Question 1 Comments:
City Water, Light & Power - Springfield, IL	Yes	In the Eastern Interconnection, it's probably good that not all regions shed load and the same frequencies. Doing so could lead to unstable conditions when the grid is already stressed.
Response: The SDT disagrees that having all regions shed load at the same frequency could lead to an unstable condition, however, the SDT confirms that it is not necessary for all regions to shed load at the same frequencies.		
Manitoba Hydro	Yes and No	Manitoba Hydro agrees that region must have the flexibility to institute a UFLS that meets its region's topology requirements. Manitoba Hydro also agrees that the SDT should develop requirements based on system performance. However, the performance targets outlined in the characteristics document are not all appropriate for every region (specifics described in following comments).
Response: Please see our responses to your comments on the following questions.		
Entergy	Yes and No	In general, we agree with the specifics prescribed by the drafting team and believe it is in the best interest of reliability to develop specific operating characteristics for each region. However, we do not agree with the design parameters set in section 4.
Response: Please see our responses to your comments on Questions 3 and 4.		
Southwest Power Pool	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not necessarily include those specific characteristics as requirements in the Regional Standard.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
Bandera Electric Cooperative	Yes	The Texas Regional Entity Regional Underfrequency Standard Drafting Team (TRE UFLS SDT) agrees with the direction that the NERC team is proposing. Performance outcomes should be the focus of the regional standards development to allow for the proper integration of practices that have long been based on regional differences and practices. Those practices, where they obviously lend themselves to achieving the expected reliability outcomes, should be respected and incorporated in the development of these new regional standards.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		

Organization	Question 1:	Question 1 Comments:
Southern Company Services, Inc	Yes	This approach allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
SERC	Yes	This approach allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
Progress Energy Carolinas, Inc.	Yes	This approach allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
Independent Electricity System Operator	Yes	We support this approach
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
Georgia Transmission Corporation	Yes	This will allow each region to develop standards that meet the specific needs of their region
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
NPCC	Yes	
Grand River Dam Authority	Yes	
ERCOT	Yes	
Florida Power & Light	Yes	

Organization	Question 1:	Question 1 Comments:
American Electric Power (AEP)	Yes	
Louisiana Generqting, LLC	Yes	
Orrville Utilities	Yes	
Florida Reliability Coordinating Council	Yes	
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	
We Energies	Yes	
E.ON U.S.	Yes	
PacifiCorp	Yes	
Transmission Reliability Program	Yes	
Duke Energy	Yes	
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		

2. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must arrest frequency decline at no less than 58.0 Hz. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Summary Consideration:

The SDT reviewed the comments received and made several conforming changes to the performance characteristics (now requirements) and/or provided the commenter with a response explaining the team's intent.

- Several commenters requested that the SDT clarify if the intent of this performance characteristic is to ensure an entity's UFLS scheme operates in its entirety prior to 58.0 Hz or that the system frequency must never drop below 58 Hz. The SDT clarified that the intent of the characteristic is that the system must be designed such that frequency does not drop bellow 58.0 Hz for an imbalance up to and including 25%.

- Many commenters indicated in their comments that the terms used in the performance characteristic "imbalance between load and generation" and "at least 25 percent" should be modified or clarified. In response to these comments, the SDT modified the performance characteristic (now Requirement R6) to clarify that an imbalance = (load – actual generation output)/ (load) of up to 25 percent within the identified island. Compliance with the performance characteristics when the imbalance is greater than 25% is not required by this standard. The SDT believes that the proposed characteristics values are achievable for generator deficits up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

- Some commenters indicated that the 25% stated in the characteristic should represent that amount of load at system peak that could be shed by UFLS relays. The SDT clarified that the 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The intent is that this would work for any load level (peak, off-peak, etc.).

- Several of the comments received indicated that UFLS should be used as a safety net based on installation requirement rather than performance requirements. Further, as worded the performance characteristic is almost impossible to meet unless all load is on UFLS. The SDT clarified that the design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6).

- Several comments indicated that the phrase "identified island" requires clarification. Is it required that the entity identify any island that has the possibility of being formed as a result of a system disturbance? And if so, it is not appropriate for these characteristics to require every possible island to meet the load mismatch criteria. The SDT clarified that it is not the intent to identify every possible island or perform an exhaustive analysis. However, it is necessary to identify island(s) as a basis for designing the UFLS program (Requirement R5). The SDT clarified requirements concerning identification of islands in Requirements R3, R4, and R5. The SDT believes that analysis to determine islands does not need to predict how island boundaries might form in future events.

Organization	Question 2	Question 2 Comments:
American Electric Power (AEP)	No Revise the design parameter as noted in the comments	The statement "the UFLS must arrest frequency decline at no less than 58.0 Hz" needs to be clarified. Is the intent of this characteristic to ensure an entity's UFLS scheme operates in its entirety prior to 58.0 Hz or is it to say that the system frequency must never drop below 58.0 Hz? **Response:** The intent of the statement is that the system be designed such that frequency does not drop below 58.0 Hz for generator deficits up to and including 25%. In addition, the "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. Compliance with performance characteristics when the imbalance is greater than 25 % is not required by this standard. The SDT believes that proposed performance characteristics values are achievable for generator deficits up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.
PPL Generation	No Revise the design parameter as noted in the comments	Some existing generating facilities may have equipment limitations or specific protection issues which require the generator to trip at a frequency level above 58 Hz. This can result in a mis-coordination between the UFLS program and the generator protective settings. The 58 Hz value can be used as the guideline, but provision must be included to allow deviation from the guideline if mis-coordination of UFLS/Generator Frequency protective settings exist and valid technical reasons are provided by a legacy generating facility. See comment to question 1 for further details.
Response: The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: “To ensure that generators will not trip off-line during specified voltage and frequency excursions.” The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.		
Midwest ISO	No Revise the design parameter as noted in the comments	We understand that the 25% stated in the question represents the amount of load at system peak that could be shed by UFLS relays. If our understanding is correct, we support the design parameter and request that the drafting team make it clearer in the characteristics that this is based on system peak load. If not, we request the drafting to change the design parameter to match our understanding.
Response: The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The intent is that this would work		

Organization	Question 2	Question 2 Comments:
for any load level (peak, off-peak, etc.). The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.		
PJM	No Revise the design parameter as noted in the comments	In Item 4, the statement “at least 25 percent” should be changed to “at most 25 percent”. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. As it is currently worded, the requirement is almost impossible to meet unless all load is on UFLS. We do not believe this was the intent of the drafting team. UFLS should be used as a safety net, based on installation requirements rather than performance requirements. As it is currently worded, if your UFLS load shedding does not arrest a blackout, you could potentially be found non-compliant. **Response:** The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6).
Florida Reliability Coordinating Council	No Revise the design parameter as noted in the comments	The context of the phrase “identified island” requires clarification. We read the characteristics document to say the Regional Entity is required to develop a standard with UFLS that specifies the entity(s) responsible for identifying potential islands. We believe this means that the Regional Entity will name a group, such as the FRCC Stability Working Group to determine any islands that should meet the requirements of paragraph 2 in the characteristics document. However, we feel that the characteristic could potentially be misinterpreted as requiring the identification of ?any island? that has the possibility of being formed as the result of a system disturbance. It is not appropriate for these characteristics to require every possible island to meet the load mismatch criteria. **Response:** It is not the intent to identify every possible island or perform an exhaustive analysis. However, it is necessary to identify island(s) as a basis for designing the UFLS program (Requirement R5). The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5. The SDT believes that analysis to determine islands does not need to predict how island boundaries might form in future events. The characteristics should make it clear that the program design should protect significant islands that could be created with credible multiple contingencies. **Response:** The SDT agrees with the spirit of this comment. Requirement R3 will require the group of Planning Coordinators to develop criteria, considering historical events and system studies, to select portions of the Bulk

Organization	Question 2	Question 2 Comments:
		Electric System that may form islands.
Florida Power & Light Co.	No Revise the design parameter as noted in the comments	There may be low probability scenarios where islanding occurs with a load and generation imbalance significantly higher than 25%. The proposed wording could be interpreted to include any conceivable combination of contingencies and operating conditions that leads to islanding. The words at least 25% should be replaced with up to 25%. Alternatively the words identified island(s) could be removed to prevent such an expansive interpretation.
Response: The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5.		
Exelon	No Revise the design parameter as noted in the comments	The wording in Requirement 4 is such that the phrase 'at least 25 per cent imbalance' should be changed to 'a maximum of 25 per cent imbalance'. There should be a size specification on 'identified island' such that it is meaningful to the bulk electric system.
Response: The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5.The SDT disagrees that there should be a size specification for islands, but has modified the requirement to apply to islands containing portions of the Bulk Electric System. The islands identified should be able to meet the performance characteristics for the given conditions.		
Ameren	No Revise the design parameter as noted in the comments	We agree that NERC should establish a minimum percentage of peak load that should be used for in design of UFLS. **Response:** The 25% represents the imbalance between load and generation not necessarily the amount of load to be included in the UFLS program. However, the NERC SDT should provide reasons for their recommendation. **Response:** The 25% represents the imbalance between load and generation not necessarily the amount of load to be included in the UFLS program. The SDT selected the design level of imbalance between load and generation based on a review of the bases for the existing UFLS programs, and notes that it may be necessary for UFLS programs to shed more than 25% of load in order to achieve the performance requirements in Requirement R6. Again, we suggest that regions and subregions within the same interconnection should coordinate their UFLS design parameters. **Response:** Characteristic 3 (Requirement R4) was intended to require that the regional standards ensure

Organization	Question 2	Question 2 Comments:
		coordination occurs on an inter-regional basis.
Alliant Energy	No Revise the design parameter as noted in the comments	The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard. Throughout NERC characteristic list, the words “conditions resulting from an imbalance between load and generation of at least 25%” are used in relation to stated performance objectives. The words “of at least” create confusion as well as the undefined term “imbalance”. The MRO has assumed this means that criteria must be met at the maximum overload level each Regions UFLS program is designed to cover, with all Regions having to shed a minimum of at least 25% of system load. However, this could also mean that criteria only has to be met for a 25% imbalance. This needs to be more clearly stated. The MRO agrees with the concept of NERC establishing a minimum load shedding level for all regions, but we do not know what a 25% imbalance is supposed to be. The definition of imbalance is not given but there is a definition that is common to the subject of UFLS, where overload = OL = (remaining generation — load)/ (remaining generation). To us, imbalance = OL, then: OL = -.25 = (gen ? load)/gen = (.8-1)/.8 This implies 20% load shedding. A 20% load shedding requirement seems a little low. A 25% minimum load shedding requirement seems more reasonable, but each Region would need to consider if that is adequate to satisfy their internal needs. In any event, minimum load shedding requirements should be explicitly stated as X% of load. **Response:** The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. We agree that a 20% load shedding requirement is low; however, the proposed definition implies a minimum load shedding of 25% as the commenter anticipated. The 58.0 Hz appears to have more of a philosophical basis rather than being solely related to generation protection

Organization	Question 2	Question 2 Comments:
		needs. If generation protection is the issue, then a 58 Hz minimum frequency criteria would not be appropriate for all islands. An island consisting of hydro units could easily accept minimum frequencies below 58 Hz for extended periods. **Response:** The basis for the performance characteristics is coordination with generation protection. We agree that hydro units have wider frequency bands, but any island would not necessarily consist only of hydro units. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of interconnection. As a practical matter, 58 Hz, as average system frequency, is probably a reasonable minimum frequency target for design work, at least for programs that shed 30% load or less. UFLS programs which need to shed more load can increase starting frequencies to improve the minimum frequency to some extent, but may need to accept momentary dips below 58 Hz provided this coordinates with overall generation protection. If this becomes NERC performance criteria, then we anticipate there needs to be a way to allow exceptions when appropriate. **Response:** The SDT believes that 58 Hz is achievable for an imbalance up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. We also have concerns that minimum frequency seen in simulations is quite subjective, it depends on many specific details such as the specific overload level modeled, as well as the assumptions made for load damping, system inertia, UFLS details including total tripping times of load, capacitor tripping, governor response, etc. It is easier at the Regional level to resolve what range of conditions/assumptions/modeling issues need to be considered. **Response:** The SDT agrees that many factors affect simulation performance and need to be worked out by the Planning Coordinators during the design of the UFLS program. If any generators have unreasonable frequency characteristics that can be changed, then the Standard should require them to make appropriate changes. **Response:** This is not the intent of the proposed standard. The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: “To ensure that generators will not trip off-line during specified voltage and frequency excursions.”

Organization	Question 2	Question 2 Comments:
E.ON U.S.	No Revise the design parameter as noted in the comments	See Response to Question 9.
Response: Please see our response to your comment to Question 9.		
Manitoba Hydro	No Revise the design parameter as noted in the comments	While 58 Hz may be appropriate for thermal units, hydro units can operate at lower frequencies. Manitoba Hydro's system is predominantly hydro units, and given our system topology, a 58 Hz cut off is not appropriate to balance our load and generation when our system is separated from the BES. There should be some provision made for systems that are not tightly interconnected with the rest of the BES. Coordination of UFLS and generator protection within the region would then become a very important component of this performance metric.
Response: The basis for the performance characteristics is coordination with generation protection. We agree that hydro units have wider frequency bands, but any island would not necessarily consist only of hydro units. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of an interconnection. The SDT believes that 58 Hz is achievable for an imbalance up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
American Transmission Company	No Revise the design parameter as noted in the comments	With respect to the 25 percentage (Characteristic 4), rather than base UFLS program requirements on system conditions that may have variable underlying assumptions, a better approach might be to specify that UFLS programs be required to shed a minimum percentage of potential island load. **Response:** The SDT has elected to specify the imbalance rather than percentage of load shed so as not to be overly prescriptive on details of UFLS program design and to establish common performance requirements to facilitate coordination between the Planning Coordinators. In addition, the term, "imbalance between load and generation condition", is ambiguous and not clearly defined. Requiring ULFS programs be designed to shed at least a specified percent of potential island load is suggested. We interpret that the phrase "at least" implies that some Regional standards may require a higher percentage for different potential islands depending on the nature of load, generators, protection schemes, and dispatch within the island. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.

Organization	Question 2	Question 2 Comments:
		With respect to the 58.0 Hz value (Characteristic 4.1), we agree that this value seems reasonable in general. However, for some potential islands the appropriate frequency limit might be higher or lower than 58.0 Hz based on the nature of the load, generators, protection schemes, and dispatch in the island. **Response:** The SDT believes that 58 Hz is achievable for an imbalance up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. An absolute, continent-wide value may not be appropriate. The Characteristics could require that the proper frequency limit be investigated and established for each potential island. The proper frequency limit should be re-examined and changed, if necessary, each time the UFLS program for a potential island is re-assessed. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of an interconnection. If any generator limitations cause an unreasonable frequency limit and any of these limitations can be changed, then the Standard should require the Generator Owner to make appropriate changes. **Response:** This is not the intent of the proposed standard. The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: "To ensure that generators will not trip off-line during specified voltage and frequency excursions."
FirstEnergy Corp.	No Revise the design parameter as noted in the comments	The document should be revised to indicate imbalances of "25 percent or less" instead of "at least 25%". If a condition occurred that resulted in a very large imbalance, perhaps much greater than 50%, it may not be possible to arrest the frequency decline to no less than 58 Hz.
Response: The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/(load) of up to 25 percent within the identified island.		
NPCC	Yes	We agree that arresting frequency decline at no less than 58.0 Hz is an appropriate design parameter in most interconnections to ensure coordination with the generator trip requirements to be proposed in PRC-024. However, in some interconnections such as Québec, where generator physical characteristics result in generator underfrequency

Organization	Question 2	Question 2 Comments:
		trip settings below the curve to be proposed in PRC-024, Regional Reliability Standards should be allowed to permit exceptions to this design parameter.
Response: The SDT agrees that provisions for differences for interconnections within a region may be permitted in the form of a Variance as outlined in the NERC Rules of Procedures.		
Bandera Electric Cooperative	Yes	In general, the TRE UFLS SDT believes a UFLS program development for recovery from a frequency excursion in an event that utilizes a 25% contribution within a system allowed to go no further than 58.0 Hz is reasonable. Further, we believe this set of parameters makes sense from the standpoint of the protection of certain equipment from sustained low frequency operation. The parameters are also viewed as essential to the protection of components of low pressure condensing turbines, which are very sensitive to low frequency operation and can quickly develop sub-standard frequency resonance conditions which can lead to catastrophic failures. The TRE UFLS SDT however does question the nature of the wording of the performance criteria "...an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s)" Is the above stated incorrectly? Can the BES remain at a frequency greater than 58.0 Hz with a 25% imbalance between load and generation? Can generation maintain 125% loading without tripping and frequency collapse? Is the statement to imply that 25% of the load should be controlled by UFLS relays? Should the 25% be stated?
Response: The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. Compliance with performance characteristics when the imbalance is greater than 25 % is not required by this standard. The SDT believes that proposed performance characteristics values are achievable for generator deficits up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
PacifiCorp	Yes	Location of generation, load centers and associated transmission interconnections between specific geographical area impact the UFLS study results, especially in WECC region. It would be helpful if RRO would identify credible islands (bubbles) for UFLS studies within RRO and designate responsible parties to conduct overall UFLS studies as per PRC-006. **Response:** Requirement R3 will require the group of Planning Coordinators to develop criteria, considering historical events and system studies, to select portions of the Bulk Electric System that may form islands.
Southwest Power Pool	Yes	Our understanding is that we would continue to use a multi-step UFLS scheme similar to what is being utilized today and that drastic changes to these existing schemes would be avoided.
Response: This in line with the SDT's intent.		

Organization	Question 2	Question 2 Comments:
ERCOT	Yes	Arresting frequency before 58.0Hz for at least 25% load/generation mismatch is a reasonable expectation.
Southwest Power Pool	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not necessarily include those specific characteristics as requirements in the Regional Standard.
Southern Company Services, Inc	Yes	This is a reasonable parameter and apparently coordinates with the most recent thinking of the Generator Verification Standards Drafting Team.
SERC	Yes	This is a reasonable parameter and apparently coordinates with the most recent thinking of the Generator Verification Standards Drafting Team.
Progress Energy Carolinas, Inc.	Yes	This is a reasonable parameter and, based on our understanding, apparently coordinates the most recent thinking of the Generator Verification Standards Drafting Team.
Entergy	Yes	This is a reasonable parameter and apparently coordinates with the most recent thinking of the Generator Verification Standards Drafting Team.
City Water, Light & Power - Springfield, IL	Yes	
Grand River Dam Authority	Yes	
Florida Power & Light	Yes	
Louisiana Generqting, LLC	Yes	
Orrville Utilities	Yes	
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	

Organization	Question 2	Question 2 Comments:
We Energies	Yes	
Transmission Reliability Program	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Georgia Transmission Corporation	Yes	

3. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that frequency does not remain below 58.5 Hz for greater than 10 seconds, cumulatively, and frequency does not remain below 59.5 Hz for greater than 30 seconds, cumulatively. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Summary Consideration:

The Underfrequency Load Shedding drafting team reviewed responses to this question and based on these comments made several conforming and/or clarifying changes to the performance characteristics (now Requirements).

- Many comments indicated that the term "cumulative" either should be removed or clarified because it is not easily tracked on a system level. The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. The standard does not require measuring compliance for actual events against the standard. The SDT has modified the performance characteristics (Requirement R6) to reflect this. Removal of the word "cumulative" does not preserve the intent of the performance characteristic.
- Several comments offered recommendations to revise the performance characteristic from 59.5 Hz to 59.3 Hz for 30 seconds. The SDT had selected the original performance characteristics to coordinate with typical turbine operating characteristics. Based on these comments the SDT revised the performance characteristics (Requirement R6.2) from 59.5 Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics.
- Several comments offered recommendations to revise the performance characteristic from 58.4 Hz to 59.4 Hz for up to nine minutes and continuous above 59.4 Hz. Other comments supported the performance characteristic as proposed by the SDT. Based on this support the SDT still proposes 58.5Hz for 10 seconds. The suggested settings do not coordinate with generator under-frequency time durations allowed by manufacturers.
- Some responses to this question indicate that it is more appropriate for the Planning Coordinators associated with the individual regions/islands to decide the appropriate design values, while still coordinating with other regions/islands. These responses indicated that most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. The SDT clarifies that the performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard.

Several responses to this question reiterate concerns regarding coordination with the PRC-024 drafting team expressed in prior questions. The SDT clarifies that it coordinated with the PRC-024 Generator Verification drafting team by providing the generator tripping curves to ensure that the performance characteristics do not conflict with the generator tripping curves.

Several responses to this question reiterate concerns regarding the 25% imbalance (at system peak) expressed in prior questions. The SDT clarifies that the 25% represents the imbalance between load and generation not the amount of load at system peak to be shed. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.

Organization	Question 3	Question 3 Suggested Revisions:
Grand River Dam Authority	No – Revise the design parameter as noted in the comments	What is the definition of cumulatively? Is this from the start of the event (UF), or is during the previous number of minutes, or from the beginning of time? It would appear that a better choice of a word is in order. **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. The standard does not require measuring compliance for actual events against the standard. The SDT has modified the performance characteristics (Requirement R6) to clarify. What does the load imbalance have to do with the UF decision? You either have UF or you do not, regardless of load imbalance. Or is there an intent to take no action on an UF event if there is a load imbalance less than 25%. **Response:** The SDT's intent is to address imbalances up to and including 25%. It is the SDT's intent to take action for imbalances up to and including 25%.
ERCOT	No – Revise the design parameter as noted in the comments	Operating to these design parameters seems reasonable. However, maybe the NERC standard characteristic should enforce the Region to have a methodology for determining these levels; Regional Standard should have the methodology for setting the levels to be met. Alternatively, the standard characteristic requirement should specify parameters for each Interconnection that are more technically suitable to the characteristic of each Interconnection.
Response: The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The performance characteristics are also intended to coordinate with generation characteristics that are common to all interconnections.		
Florida Power & Light	No – Revise the design parameter as noted in the comments	The term cumulatively is not defined. How is this measured? Is this over the time of the event, over the life of equipment i.e. generators etc.
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. The SDT has modified the performance characteristics (Requirement R6) to clarify.		

Organization	Question 3	Question 3 Suggested Revisions:
American Electric Power (AEP)	No – Revise the design parameter as noted in the comments	Most UFLS schemes are designed to meet the time requirements proposed by this characteristic if the load/generation imbalance is 25% or less. If the load/generation imbalance is greater than 25%, manual operator intervention (load shedding) may be required to maintain system frequency. An operator can not meet the time requirements outlined by this characteristic. The "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes.
Response: The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
PPL Generation	No – Revise the design parameter as noted in the comments	See comments to question 1.Some existing generating facilities may have equipment limitations or specific protection issues which force the generator to trip at a frequency levels and operating times that are inconsistent with the characteristic identified above. This can result in a mis-coordination between the UFLS program and the generator protective settings. The above characteristic can be used as the guideline, but provision must be included to allow deviation from the guideline if mis-coordination of UFLS/Generator Frequency protective settings exist and valid technical reasons are provided by a legacy generating facility.
Response: The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: “To ensure that generators will not trip off-line during specified voltage and frequency excursions.” The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.		
Bandera Electric Cooperative	No – Revise the design parameter as noted in the comments	The TRE UFLS SDT recommends the NERC performance criteria be revised from 59.5 Hz to 59.3 Hz. 59.5 Hz is a frequency level that should be supported by high set relays, (59.7 Hz); and when high sets are activated, the next level of intervention should be 59.3 Hz for no more than 30 seconds.
Response: Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds.		
Midwest ISO	No – Revise the design parameter as noted in the comments	We understand that the 25% stated in the question represents the amount of load at system peak that could be shed by UFLS relays. If our understanding is correct, we support the design parameter and request that the drafting team make it clearer in the characteristics that this is based on system peak load. If not, we request the drafting to change the design parameter to match our understanding.

Organization	Question 3	Question 3 Suggested Revisions:
		Response: The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. These design parameters should be coordinated with typical turbine operating characteristics. The UFLS relays should shed load to prevent permanent turbine damage. It is our understanding that a typical turbine can operate at 59.5 Hz for 30 minutes rather than 30 seconds without experiencing loss of life. Was the 30 seconds at 59.5 Hz supposed to be 30 minutes? **Response:** The SDT selected the original performance characteristics to coordinate with typical turbine operating characteristics. The SDT did intend on 59.5 Hz for 30 seconds; however, based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics. What does cumulative mean here? Is it the total operating time over a week period, a day, a year, the life of turbine? If the system frequency dips below 59.5 Hz for 15 minutes today and dips below 59.5 Hz tomorrow for 15 minutes, does that mean the UFLS relays should operate? **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
PJM	No – Revise the design parameter as noted in the comments	Please refer to the comment above for question 2. The current draft RFC standard allows the first step of UFLS to begin at 59.3 Hz. Please consider reducing this requirement to 59.3 Hz in the NERC Standard. **Response:** Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds. When discussing cumulatively, when is the accumulation timer reset: after a minute, an hour, a year? **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
Florida Reliability Coordinating	No – Revise the design parameter as noted in the	Remove of the word “cumulatively” as it is undefined and could be interpreted in several ways, but we think the intent was for a consecutive time. We believe protection engineers would interpret the times as an inclusive time frame and not as a cumulative period beyond the time span given.

Organization	Question 3	Question 3 Suggested Revisions:
Council	comments	**Response**: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. The context of the phrase “identified island” requires clarification. (See comments for Question No. 2.) **Response:** See response to question No. 2
Florida Power & Light Co.	No – Revise the design parameter as noted in the comments	The meaning of the term cumulatively in this context is unclear. If redefined as specific to one event, it would still be an unnecessary qualifier that would be difficult to apply. Remove the term cumulatively
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
Exelon	No – Revise the design parameter as noted in the comments	RFC has determined and included in its draft standard that the first step of the UFLS program may be at 59.3 Hz. Please change the parameter to include RFC level.
Response: Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds.		
Progress Energy Carolinas, Inc.	No – Revise the design parameter as noted in the comments	This design parameter is appropriate except for the requirement to "not remain below 59.5 Hz for greater than 30 seconds." Relatively quick recovery above 58.5 is appropriate to minimize the possibility of generator trips. However, at 59.5 Hz, the possibility of generator trips is greatly reduced and a more reasonable recovery time should be allowed. Recommend this be changed to "not remain below 59.5 Hz for greater than 5 minutes." ANSI standard 37.106-2003 indicates that 59.5 Hz for 5 minutes provides adequate margin above typical generator damage curves. This change will help reduce the potential for overshoot while still providing sufficient margin. **Response:** Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics. Additionally, the word "cumulatively" (in Characteristics 4.3 and 4.4) should be removed. Cumulatively refers more to "cumulative machine damage" and is not easily tracked on a system level (nor is it necessary on a system level). **Response:** Removal of the word “cumulative” does not preserve the intent of the performance characteristic. Instead, the SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS

Organization	Question 3	Question 3 Suggested Revisions:
		program design.
Ameren	No – Revise the design parameter as noted in the comments	We believe that the proposed time for underfrequency operation is too restrictive. The proposed time of 30 seconds of operation at 59.5 Hz does not provide the system operators with enough time to attempt to bring generation on-line to remedy the frequency undershoot. Based on our practices, tripping of generation at 59.5 Hz is not necessary and if implemented may further exacerbate the frequency decline conditions. We agree that underfrequency operation is neither optimum nor desired, but the system needs to hold together as long as possible to be able to implement operational solutions. We suggest that the SDT to quantify the risks, including appropriate review of existing (not proposed) IEEE, ANSI and other standards, associated with operating the generating equipment at 59.5 Hz (0.992 p.u.) for more than 30 seconds to support their recommendation. **Response:** The intent of the load shedding program is to stabilize frequency automatically prior to operator intervention. We agree that tripping generation may further exacerbate conditions. The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: "To ensure that generators will not trip off-line during specified voltage and frequency excursions." The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop. We also suggest the SDT to clearly define the term "cumulatively"; For example, is it per event, per life of the equipment, or something else? **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
Alliant Energy	No – Revise the design parameter as noted in the comments	The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard.

Organization	Question 3	Question 3 Suggested Revisions:
		We do not agree with the specified maximum operating times associated with the specified off-nominal frequencies. The proposal to limit time below 59.5 Hz and above 60.5 Hz to 30 seconds looks like a typo. 59.5 Hz to 60.5 Hz is the range where units can run continuously with no accelerated loss of life. Perhaps “30 seconds” should have read “30 minutes” which is still only 66% of the time specified by the MRO program for f <= 59.5 Hz. As written, the proposed criteria for time spent below 59.5 Hz and above 60.5 Hz is unacceptable. The MRO UFLS report states that generation protection cannot trip any quicker than shown below, and that utilities that need to shed more than 30% of connected load will have to relax these times to allow their load shedding to play out. MRO generation protection time delay requirement: 45 minute, frequency <=59.5 Hz? 5 minute, frequency <= 59.3 Hz? 1.33 minute, frequency <= 59 Hz? 30 second, frequency <= 58.4 Hz? 7.5 second, frequency <= 58.0 Hz? instant trip at 57.6 Hz In the MRO UFLS study simulations, we estimated our worst-case time below 58.5 Hz would be approximately 9 seconds. Of course, this has to be qualified by saying “for our given assumptions”. These types of simulations only give approximate results. The proposal to limit time below 58.5 Hz to 10 seconds is going to be tight for a program which sheds more than 30% load. What we assume for governor action will have considerable effect on how much time is spent below 58.5 Hz. The MRO tried to design a program that will ensure frequency recovery even if we get no net governor response. The MRO study looked at a range of imbalances that an UFLS program has to respond to, and factored in uncertainties. 100?s of cases were run to cover a range of imbalances, range of damping assumptions, and a range of system based inertia. In looking at all of the results in total, the resulting time spent below a given frequency took on the form of a probability density function. Typical times below a given frequency are perhaps more representative of what the typical exposure is for generation. However we coordinated generation protection according to the worst case times with enough margin to provide a degree of comfort. The actual loss of life a generator will be exposed to for some arbitrary UFLS event will most often be less than what these generator protection trip settings reflect as the first line of defense is the load shedding program itself. Under most circumstances, we will never spend enough time in the frequency trip bands to actually trip generation. To view the full report of the MRO UFLS please see the MRO website:http://www.midwestreliability.org/03_reliability/assessments/report_draft_03_12_final_clean.pdf **Response:** The SDT selected the original performance characteristics to provide coordination with typical turbine operating

Organization	Question 3	Question 3 Suggested Revisions:
		characteristics. SDT did intend on 59.5 Hz for 30 seconds; however, based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics.
E.ON U.S.	No – Revise the design parameter as noted in the comments	See Response to Question 9.
Response: Please see our response to your comment to Question 9.		
Manitoba Hydro	No – Revise the design parameter as noted in the comments	Manitoba Hydro echo's the MRO's concerns: "The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. "
Response: The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard.		
CenterPoint Energy	No – Delete the design parameter	As stated previously, CenterPoint Energy believes this effort should be postponed. Alternatively, this proposed design parameter should be deleted until coordination with the PRC-024 drafting team can be firmly established. **Response:** The SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team (GV SDT) by providing the generator underfrequency performance curve to ensure that the performance characteristics do not conflict with the generator off nominal capability curve. The SDT will continue to coordinate with the GV SDT and we believe it does not matter whether PRC-006 or PRC-024 is approved first as long as this coordination exists. If the design parameter is not deleted, CenterPoint Energy recommends the following values to place proper balance and emphasis on system reliability as system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions: 58.4 Hz to 59.4 Hz for up to 9 minutes and continuous above 59.4 Hz. **Response:** Based on industry support the SDT still proposes 58.5Hz for 10 seconds. The suggested settings do not coordinate with generator under-frequency time durations allowed by manufacturers. Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still

Organization	Question 3	Question 3 Suggested Revisions:
		maintaining coordination with typical turbine operating characteristics.
FirstEnergy Corp.	No – Revise the design parameter as noted in the comments	1. Although we agree that there needs to be a low set-point duration of no greater than 10 seconds for frequencies below 58.5 Hz, we are not sure if the appropriate first set-point should be set at 59.5 Hz. Some systems may be able to function reliably at 59.4 Hz for more than 30 seconds, so we ask the SDT to investigate this or provide the technical rationale for choosing 59.5 Hz. **Response:** Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics. 2. When using the term "cumulatively" in this characteristic, when is the accumulation timer reset: a minute, an hour, a year? We are not clear if this is based on a design parameter or an "after-the-fact" performance review. We ask the SDT to provide clarification on this term. **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. 3. As stated previously, the document should be revised to indicate imbalances of "25 percent or less" instead of "at least 25%". The design parameters would not be achievable if an extremely high imbalance occurred. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/(load) of up to 25 percent within the identified island.
Entergy	No	Entergy experiences some under-frequency relay trips due to transient contributions from induction motors with UF relays set to trip at 59.3 Hz. Relay trip settings at 59.5 Hz will increase the likelihood of these nuisance trips with attendant two-hour restart times for large commercial / industrial loads. We suggest the 59.5 Hz, 30 second, requirement is an overly restrictive requirement and we believe the setting should be lowered to at least 59.3 Hz. Lowering this requirement will give regions greater latitude when developing the design requirements of their standard.
Response: Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics.		
American Transmission	No – Revise the design parameter	With respect to the 25 percentage (Characteristic 4), refer to comments for Question 2. **Response**: The SDT has elected to specify the imbalance rather than percentage of load shed so as not to be overly

Organization	Question 3	Question 3 Suggested Revisions:
Company	as noted in the comments	prescriptive on details of UFLS program design and to establish common performance requirements to facilitate coordination between regions. With respect to the 10-second and 30-second underfrequency values (Characteristic 4.2), these values may be reasonable in general. However, for some potential islands the appropriate frequency limits might be higher or lower based on the nature of the load, generators, protection schemes, and dispatch in the island. Absolute, continent-wide values may not be appropriate. The Characteristics could require that the proper frequency limits be investigated and established for each potential island. The proper frequency limit should be re-examined and changed, if necessary, each time the UFLS program for a potential island is re-assessed. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of an interconnection. If any generator limitations cause an unreasonable frequency limit and any of these limitations can be changed, then the Standard should require the Generator Owner to make appropriate changes. **Response:** This is not the intent of the proposed standard. The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: "To ensure that generators will not trip off-line during specified voltage and frequency excursions."
Indiana Municipal Power Agency	No – Revise the design parameter as noted in the comments	The term cumulatively is confusing. It either needs to be clarified or removed.
Response: Removal of the word "cumulative" does not preserve the intent of the performance characteristic. Instead, the SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
Duke Energy	No – Revise the design parameter as noted in the comments	The time frames stated in these criteria seem overly conservative. Thirty seconds at 59.5 Hz would likely create expensive and unnecessary relay setting changes. Recommend changing the requirement to "59.5 Hz for greater than 5 minutes." **Response:** Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics.

Organization	Question 3	Question 3 Suggested Revisions:
		The Generator Verification SDT (PRC-024) is evaluating the appropriate envelope for protection of generator equipment. The envelope established by these criteria must be coordinated with generator protection envelope. **Response:** The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: "To ensure that generators will not trip off-line during specified voltage and frequency excursions." The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop. The word "cumulatively" is confusing in this context. Since this is generally related to equipment and not system studies, recommend deleting "cumulatively" from the requirements. **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
PacifiCorp	Yes	same comment as item 2 to identify UFLS study bubble by RRO. Location of generation, load centers and associated transmission interconnections between specific geographical area impact the UFLS study results, especially in WECC region. It would be helpful if RRO would identify credible islands (bubbles) for UFLS studies within RRO and designate responsible parties to conduct overall UFLS studies as per PRC-006.
Response: Requirement R3 will require the group of Planning Coordinators to develop a procedure to investigate and locate portions of the Bulk Electric System that may form islands including how historical events and system studies were considered.		
Southwest Power Pool	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not necessarily include those specific characteristics as requirements in the Regional Standard.
Response: The SDT confirms that this was the original intent; however, the SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard that requires the Planning Coordinators to design UFLS programs that adhere to the performance characteristics (Requirement R6).		
Southern Company Services, Inc	Yes	No Additional Comment.
Louisiana Generqting,	Yes	

Organization	Question 3	Question 3 Suggested Revisions:
LLC		
Orrville Utilities	Yes	
City Water, Light & Power - Springfield, IL	Yes	
NPCC	Yes	
SERC	Yes	
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	
We Energies	Yes	
Transmission Reliability Program	Yes	
Independent Electricity System Operator	Yes	
Georgia Transmission Corporation	Yes	

4. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that the frequency overshoot resulting from operation of UFLS relays will not exceed 61.0 Hz for any duration and will not exceed 60.5 Hz for greater than 30 seconds, cumulatively. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Summary Consideration:

The UFLS Standard Drafting team reviewed comments to this question and made several conforming changes to the performance characteristics (now requirements).

- Numerous industry comments indicated that while this design parameter is appropriate as an overall system design obective the limits are overly restrictive and do not appear to coordinate with any equipment limitations. Based on these comments the SDT adjusted the characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).

- Several industry comments indicated that operating to these parameters appears reasonable; however, it would be preferrable if the SDT specify parameters for each interconnection that are more technically suitable to the characteristic of each interconnection. The SDT clarifies that the performance characteristics are intended to coordinate with generation characteristics that are common to all interconnections. In addition, the SDT believes that the performance characteristics are achieveable for imbalances up to and including 25%. For deficiencies up to 25% these performance characteristics must be met; however, for deficiencies exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

- Several industry comments indicated that “cumulative” needs clarification. The SDT clarifies that cumulative is “per event simulated” to verify that the performance characteristics are achieved by the UFLS program design. Various requirements were modified to reflect that cumulative is per event simulated.

- Several industry comments suggested that a mimium size of the postulated island should be specified and it should be of sufficient size to affect the Bulk Electric System and there should be a distinction with differing requirements between the entire Eastern Interconnection and a potential frequency overshoot in a much smaller identified island. The SDT believes that the UFLS programs must be designed such that all interconnected systems will meet common performance characteristics. Common performance characteristics facilitate coordination between regions. An island could be subject to other performance characteristics in addition to the common performance characteristics for imbalances greater than 25% if the Regional Entities develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. In addition, the SDT clarified requirements concerning identification of islands in Requirements R3, R4, and R5. The SDT disagrees that there should be a size specification for islands, but has modified the requirement to apply to islands

containing portions of the Bulk Electric System. The islands identified should be able to meet the performance characteristics for the given conditions.

Organization	Question 4	Question 4 Suggested Revisions:
NPCC	No – Revise the design parameter as noted in the comments	We agree this design parameter is appropriate as an overall system design objective. However, this objective cannot be met through the UFLS program design alone in the absence of adequate generating unit governing response. We recommend that applicability of this design parameter be limited to islands that exhibit a frequency response of at least 1 percent of peak island load per 0.1 Hz.
Response: Rather than changing applicability of this performance characteristic, the SDT adjusted the characteristic. Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds.		
ERCOT	No – Revise the design parameter as noted in the comments	Operating to these design parameters seems reasonable. However, maybe the NERC standard characteristic should enforce the Region to have a proof of methodology of determining these levels, Regional Standard should have the methodology for setting the levels to be met. Alternatively, the standard characteristic requirement should specify parameters for each Interconnection that are more technically suitable to the characteristic of each Interconnection. In addition to the comment; does the NERC SDT have supporting documentation for restricting frequency overshoot to 61Hz? Request NERC Generation Verification SDT for reasoning/explanation.
Response: The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The performance characteristics are also intended to coordinate with generation characteristics that are common to all interconnections. Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Florida Power & Light	No – Revise the design parameter as noted in the comments	Cumulatively needs to be defined. Is this cumulative over the event, cumulatively over the life of the equipment? The 61Hz and 60.5Hz limits are overly restrictive and do not appear to coordinate with any equipment limitations

Organization	Question 4	Question 4 Suggested Revisions:
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
American Electric Power (AEP)	No – Revise the design parameter as noted in the comments	UFLS schemes are designed to account for frequency overshoot by breaking the UFLS scheme up into separate steps (verified by dynamic simulation). Is the intent of this characteristic to specify parameters for the amount of load included in each UFLS step and/or to specify parameters for unit overspeed trip settings? Clarification is needed not only for the intent of this characteristic but also regarding the foundation of the timing requirements. In addition, the "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes.
Response: Unit overspeed trip relay settings are to be limited according to PRC-024. The UFLS performance characteristics are intended to coordinate with PRC-024 in order to prevent unnecessary loss of generation. Timing requirements need to be specified by the group of Planning Coordinators to prevent frequency overshoot above the performance characteristic values. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
PPL Generation	No – Revise the design parameter as noted in the comments	See comments to question 1.Some existing generating facilities may have equipment limitations or specific protection issues which force the generator to trip at a frequency levels and operating times that are inconsistent with the values identified above. This can result in a mis-coordination between the UFLS program and the generator protective settings. The above characteristic can be used as the guideline, but provision must be included to allow deviation from the guideline if mis-coordination of UFLS/Generator Frequency protective settings exist and valid technical reasons are provided by a legacy generating facility.
Response: The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: "To ensure that generators will not trip off-line during specified voltage and frequency excursions." The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.		
Bandera Electric Cooperative	No – Delete the design parameter	The TRE UFLS SDT believes that the NERC standard should not define the frequency overshoot limit; instead, the NERC standard should state this as a requirement for the region to establish as part of a regional UFLS standard. For example, the NERC standard might state as follows: "The Regional Standard shall define the frequency overshoot it

Organization	Question 4	Question 4 Suggested Revisions:
		determines appropriate in arresting the imbalance between load and generation."
Response: The performance characteristics are intended to coordinate with generation characteristics that are common to all interconnections. The UFLS design parameters can be devised by the Planning Coordinator(s) and the SDT has assigned the Planning Coordinators this responsibility in the proposed standard.		
Louisiana Generqting, LLC	No – Revise the design parameter as noted in the comments	61Hz and 60.5Hz limits are overly restrictive and do not appear to coordinate with any equipment limitations
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Midwest ISO	No – Revise the design parameter as noted in the comments	We understand that the 25% stated in the question represents the amount of load at system peak that could be shed by UFLS relays. If our understanding is correct, we support the design parameter and request that the drafting team make it clearer in the characteristics that this is based on system peak load. If not, we request the drafting to change the design parameter to match our understanding. **Response:** The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. These design parameters should be coordinated with typical turbine operating characteristics. If a turbine can operate at 60.5 Hz for 30 minutes before experiencing any loss of life, the design parameters should reflect this. It is our understanding that a typical turbine can operate at 60.5 Hz for 30 minutes rather than 30 seconds without experiencing loss of life. Was the 30 seconds at 60.5 Hz supposed to be 30 minutes? **Response:** The SDT selected the original performance characteristics to provide coordination with typical turbine operating characteristics. Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).
Southern	No – Revise the	These parameters are overly restrictive. We recommend to change the statement to "will not exceed 61.5 Hz for any

Organization	Question 4	Question 4 Suggested Revisions:
Company Services, Inc	design parameter as noted in the comments	duration and will not exceed 60.5 Hz for greater than 5 minutes?" A frequency of 61.8 Hz results in a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin. ANSI standard 37.106-2003 indicates that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. Our proposed parameters allow time for generator governors to operate and for some load restoration to correct overshoot.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
PJM	No – Revise the design parameter as noted in the comments	"for any duration" is too difficult to meet. Substitute with a short time frame.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Florida Reliability Coordinating Council	No – Revise the design parameter as noted in the comments	The 61.0 hertz ceiling for frequency recovery seems too low. Is there any technical justification for this level? A more appropriate limit might be 61.8 hertz due to the number of governing systems that initiate auxiliary governor action at 103% overspeed. **Response:** Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that are developing generator requirements (PRC-024). Remove of the word “cumulatively”. (See comments for Question No. 3.) **Response:** Removal of the word “cumulative” does not preserve the intent of the performance characteristic. Instead, the SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. The context of the phrase “identified island” requires clarification. (See comments for Question No. 2.) **Response:** See our response to question No. 2

Organization	Question 4	Question 4 Suggested Revisions:
SERC	No – Revise the design parameter as noted in the comments	These parameters are overly restrictive. We recommend to change the statement to "will not exceed 61.5 Hz for any duration and will not exceed 60.5 Hz for greater than 5 minutes?" A frequency of 61.8 Hz results in a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin. ANSI standard 37.106-2003 indicated that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. Our proposed parameters allow time for generator governors to operate and for some load restoration to correct overshoot.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Entergy	No	We agree with and support the SERC comments.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Northeast Utilities	No – Revise the design parameter as noted in the comments	We do not believe all generator controls are sufficiently responsive to enable this design parameter. A longer response time may be needed, or a significant improvement in governing response for connected generators.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Florida Power & Light Co.	No – Revise the design parameter as noted in the comments	A technical justification of the proposed over frequency limits does not appear to be posted with the generator verification SDT information. A target over frequency limit of 61.8 hertz is used within the FRCC. The 61.0 hertz and 60.5 hertz for 30 seconds appear to be unnecessarily low. **Response:** Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that are developing generator requirements (PRC-024). The words at least 25% should be replaced with up to 25% for the reasons discussed above.

Organization	Question 4	Question 4 Suggested Revisions:
		Response: The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The word cumulatively should be removed. **Response:** Removal of the word "cumulative" does not preserve the intent of the performance characteristic. Instead, the SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
Exelon	No – Revise the design parameter as noted in the comments	There should be a distinction and differing requirements between the entire Eastern Interconnection and a potential frequency overshoot in a much smaller identified island. Also, the minimum size of the postulated island should be specified here. It should be of sufficient size to affect the bulk electric system.
Response: The UFLS program must be designed such that all interconnected systems will meet common performance characteristics. Common performance characteristics facilitate coordination between regions. An island could be subject to other performance characteristics in addition to the common performance characteristics for imbalances greater than 25% if the Regional Entities develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5. The SDT disagrees that there should be a size specification for islands, but has modified the requirement to apply to islands containing portions of the Bulk Electric System. The islands identified should be able to meet the performance characteristics for the given conditions.		
Progress Energy Carolinas, Inc.	No – Revise the design parameter as noted in the comments	These parameters are overly restrictive. We recommend to change the statement to "will not exceed 61.5 Hz for any duration and will not exceed 60.5 Hz for greater than 5 minutes?" A frequency of 61.8 Hz results in a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin. ANSI standard 37.106-2003 indicated that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. Our proposed parameters allow time for generator governors to operate and for some load restoration to correct overshoot.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Ameren	No – Revise the design parameter	We believe that these over frequency parameters are overly restrictive. We suggest that the SDT to quantify the risks, including appropriate review of existing (not proposed) IEEE, ANSI and other standards, associated with operating the

Organization	Question 4	Question 4 Suggested Revisions:
	as noted in the comments	generating equipment above 60.5 Hz for more than 30 seconds to support their recommendation. We also suggest the SDT to clearly define the term "cumulatively"; For example, is it per event, per life of the equipment, or something else?
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024). The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
Alliant Energy	No – Revise the design parameter as noted in the comments	This a subjective performance criteria as modeling details such as load damping assumptions, inertia assumptions, and governor response assumption will all have considerable effect on performance. This type of performance objective is best evaluated and determined at the Regional level or some mechanism needs to be in place to allow aggressive load shedding programs some latitude on this. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. There are cases where overshoots above 61 Hz could be accepted for short periods. The type of units in the island also have to be considered. Hydro systems have fewer off-nominal frequency restrictions. The 30 second time limit for operating above 60.5 Hz is not at all appropriate. Units can operate continuously at 60.5 Hz with no accelerated loss of life. They can run slightly above this for a long time. Could this be a typo? Was the intention to establish at 30 minute limit? **Response:** Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).
E.ON U.S.	No – Revise the design parameter as noted in the comments	See Response to Question 9.
Response: Please see our response to your comment to Question 9.		
Manitoba Hydro	No – Revise the design parameter	Again, Manitoba Hydro echo's the MRO's concerns. Each region should determine the maximum overshoot based on

Organization	Question 4	Question 4 Suggested Revisions:
	as noted in the comments	its system topology, how it was planned and designed and the region's requirements.
Response: The performance characteristics are intended to coordinate with generation characteristics that are common to all interconnections and ensure coordination among the programs the Planning Coordinators are required to design. The UFLS design parameters can be devised by the Planning Coordinator(s) and the SDT has assigned the Planning Coordinators this responsibility in the proposed standard.		
CenterPoint Energy	No – Delete the design parameter	As stated previously, CenterPoint Energy believes this effort should be postponed. Alternatively, this proposed design parameters should be deleted until coordination with the PRC-024 drafting team can be firmly established. If the design parameter is not deleted, CenterPoint Energy recommends a value of 61.5 Hz instead of 61.0 Hz to place proper balance and emphasis on system reliability as system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that are developing generator requirements (PRC-024).		
FirstEnergy Corp.	No – Delete the design parameter	1. When using the term "cumulatively" in this characteristic, when is the accumulation timer reset: a minute, an hour, a year? We are not clear if this is based on a design parameter or an "after-the-fact" performance review. We ask the SDT to provide clarification on this term. **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. 2. We recommend that this design parameter be deleted. We feel that the characteristic is overly prescriptive. Although frequency overshoot may be a concern in some regions, it is not in all regions. In many regions the generators would automatically re-adjust to lower frequency. **Response:** This is a concern for all islands and interconnected systems. The requirement (Requirement R6.3) ensures coordination with the UFLS program and generator limitations. Governing response to over-frequency conditions should be accounted for in the design of the UFLS program.
American Transmission	No – Revise the design parameter as noted in the	With respect to the 25 percentage (Characteristic 4), refer to comments for Question 2. **Response:** The SDT has elected to specify the imbalance rather than percentage of load shed so as not to be overly

Organization	Question 4	Question 4 Suggested Revisions:
Company	comments	prescriptive on details of UFLS program design and to establish common performance requirements to facilitate coordination between regions. With respect to the continuous and 30-second overfrequency values (Characteristic 4.3), these values may be reasonable in general. However, for some potential islands the appropriate frequency limits might higher or lower based on the nature of the load, generators, protection schemes, and dispatch in the island. Absolute, continent-wide value may not be appropriate. The Characteristics could require that the proper frequency limit be investigated and established for each potential island. The proper frequency limit should be re-examined and changed if necessary each time the UFLS program for a potential island is re-assessed. If any generator limitations cause an unreasonable frequency limit and any of these limitations can be changed, then the Standard should require the Generator Owner to make appropriate changes. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of an interconnection.
Indiana Municipal Power Agency	No – Revise the design parameter as noted in the comments	The term cumulatively is confusing. It either needs to be clarified or removed.
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
Duke Energy	No – Revise the design parameter as noted in the comments	These parameters seem too restrictive. Recommend changing the statement to "will not exceed 61.5 Hz for any duration and will not exceed 60.5 Hz for greater than 5 minutes?" This is recommended because a frequency of 61.8 Hz is a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin. Also, ANSI standard 37.106-2003 indicated that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. The recommended parameter changes allow time for generator governors to operate and for some load restoration to correct overshoot.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Southwest Power	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not

Organization	Question 4	Question 4 Suggested Revisions:
Pool		necessarily include those specific characteristics as requirements in the Regional Standard.
Response: The SDT confirms that this was the original intent; however, the SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard that requires the Planning Coordinators to design UFLS programs that adhere to the performance characteristics (Requirement R6).		
We Energies	Yes	
Buckeye Power, Inc.	Yes	
Orrville Utilities	Yes	
City Water, Light & Power - Springfield, IL	Yes	
Grand River Dam Authority	Yes	
PacifiCorp	Yes	
Transmission Reliability Program	Yes	
Independent Electricity System Operator	Yes	
Georgia Transmission Corporation	Yes	

5. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that the Bulk Electric System voltage during and following UFLS operations is controlled such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than 6 seconds cumulatively, and does not exceed 1.10 for longer than 1 minute cumulatively. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Summary Consideration:

The UFLS Standard Drafting team reviewed comments to this question and made several conforming changes to the performance characteristics (now requirements). In addition, the team considered the comments and provided clarifying responses.

- Several comments expressed concern that this performance characteristic is out of place because as load is rejected to correct the frequency problem the voltage should climb. The SDT clarifies that they feel it is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.
- Several comments expressed concern that the underfrequency relays are not monitored or supervised by a volts/ hertz element and do not operate or block based on the Volts / hertz. The underfrequency relays typically do have undervoltage blocking which will block underfrequency relay operation for low voltage, but the UFLS relays have no capability to control voltage. Therefore, the UFLS relays cannot control voltage level or volts/ hertz and this requirement should be omitted from the UFLS standard characteristics.The SDT agrees with the comment; however, the intent is that over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances.
- Comments expressed confusion regarding whether this is a planning characterisitc for simulation of the UFLS or a post event measurement for compliance. The SDT clarified that this is a planning characteristic for simulation based design verification studies. It is not a post-event measurement for compliance. The proposed standard has been modified to clarify this point.
- Several comments indicated that the standard characteristic requirement should specify how to determine to which buses these voltage requirements apply for each Interconnection, at a minimum, and preferably for each Region. The SDT made a clarifying change to Requirement R6.4 which further specifies the locations to which these voltage requirements apply.

Organization	Question 5	Question 5 Suggested Revisions:
Grand River Dam Authority	No – Revise the design parameter as noted in the comments	This seems to be out of place in an UFLS scheme and may belong in an OV scheme. As load is rejected to correct the frequency problem, the voltage should climb. The generators, with the VRs, may or may not see the problem. This seems more like a hope than an item that someone can accomplish. Studies may indicate that there is no problem. But if they show a problem, what can be done? Install shunt reactors which may not help the frequency problem????
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
ERCOT	No – Revise the design parameter as noted in the comments	Is this just a planning characteristic for simulation of the UFLS, or a post event measurement for compliance? If it is included in the post event compliance analysis then it needs to be more specific on what voltage(s) are to be measured and meet the design parameters. Is it every Bus Voltage in the BES? Or a subset of critical buses for measurement? **Response:** This is a planning characteristic for simulation based design verification studies. It is not a post-event measurement for compliance. The proposed standard has been modified to clarify this point. Perhaps the NERC Standard Characteristic requests that each Region establish a methodology for determining a list of critical buses and these bus voltages are to be used for the UFLS and post event compliance analysis. Alternatively, the standard characteristic requirement should specify how to determine to which buses these voltage requirements apply for each Interconnection, at a minimum, and preferably for each Region. **Response:** The SDT modified Characteristic 4.4 (Requirement R6.4) to further specify the location (Requirements R6.4.1 and R6.4.2).
Florida Power & Light	No – Revise the design parameter as noted in the comments	The term cumulatively needs to be defined
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
American Electric Power (AEP)	No – Delete the design parameter	The foundation of the timing requirements needs to be clarified. **Response:** The technical basis for the performance characteristics was developed through a review of relevant

Organization	Question 5	Question 5 Suggested Revisions:
		industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. The SDT included more details regarding the technical justification for the performance characteristics in the comment form background (including specific IEEE standards). In addition, the "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.
Southwest Power Pool	No – Delete the design parameter	The UFLS system consists of underfrequency relays. The underfrequency relays are not monitored or supervised by a volts/ hertz element and do not operate or block based on the Volts / hertz. The underfrequency relays typically do have under voltage blocking which will block underfrequency relay operation for low voltage, but the UFLS relays have no capability to control voltage. Therefore, the ufls relays cannot control voltage level or volts/ hertz and this requirement should be omitted from the UFLS standard characteristics.
Response: The SDT agrees with the comment; however, the intent is that over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances.		
Bandera Electric Cooperative	No – Revise the design parameter as noted in the comments	The TRE UFLS SDT feels that, due to the interplay between load and generation components during a firm load shedding event, it would seem impractical to decompose their individual contributions to the volts/Hz ratio; therefore, compliance enforcement would likely prove to be impossible. **Response:** This is a planning characteristic for simulation based design verification studies. It is not a post-event measurement for compliance. The TRE UFLS SDT feels that the NERC standard should not specify the relay coordination requirements with generation protection relays. Instead, the NERC standard should state as a requirement for each region to establish as part of the UFLS standard a planning study to determine adequacy and consistency with other standards. For example, the NERC standard might state as follows: "The Regional Standard shall address the requirement for the UFLS to coordinate with existing regional generation relaying requirements." As written, the proposed performance criteria may conflict with ERCOT's Operating Guide 3.1.4.6 where v/Hz is specified. **Response:** The UFLS program must be designed such that all interconnected systems will meet common

Organization	Question 5	Question 5 Suggested Revisions:
		performance characteristics. The SDT acknowledges that ERCOT 3.1.4.6 (1.16 pu v/Hz for 1.5 seconds); is more conservative than the proposed performance characteristic (Requirement R6.4).
Louisiana Generqting, LLC	No – Revise the design parameter as noted in the comments	the interplay between the generation control and the load shedding programs will make it difficult to meet this requirement and cumulatively need to be defined.
Response: The SDT considers that the performance characteristic is achievable and a necessary requirement. Lack of coordination between generation control and under frequency load shedding program could result in inappropriate generator tripping and result in a failure of the overall program. The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
Midwest ISO	No – Delete the design parameter	V/Hz design parameters are appropriate for generation protection. We don't believe that is should be considered here as design parameter.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
Southern Company Services, Inc	No – Delete the design parameter	A volts per hertz requirement is more appropriate in a generator protection standard.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
PJM	No – Delete the design parameter	Add the units after the numbers mentioned (p.u. V/Hz). **Response:** The SDT believes that it is correct as stated. When discussing cumulatively, when is the accumulation timer reset: after a minute, an hour, a year? **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics

Organization	Question 5	Question 5 Suggested Revisions:
		are achieved by the UFLS program design.
Florida Reliability Coordinating Council	No – Revise the design parameter as noted in the comments	Replace the words "Bulk Electric System" with "generator terminal". The volts per hertz limits contained in 4.4 correspond to recommendations typical for generators. The temporary overvoltages (TOV) that will follow islanding with UFLS action tend to be significantly higher on the EHV transmission system since generators will be absorbing Vars and pulling voltage down. The EHV TOV capabilities are generally much higher than generator V/Hz limits and may be more variable due to individual grid design practices regarding basic insulation level and lightning arrester ratings. **Response:** The buses for which this should apply should be determined according to volts per Hz limits on applicable equipment, etc. In addition, SDT clarifies that the requirement does not address overvoltage limits. The SDT modified Characteristic 4.4 (Requirement R6.4) to further specify the location (Requirements R6.4.1 and R6.4.2). Remove of the word “cumulatively”. (See comments for Question No. 3.)The context of the phrase “identified island” requires clarification. (See comments for Question No. 2.) **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
SERC	No – Delete the design parameter	This requirement is very difficult to measure. A volts per hertz requirement is more appropriate in a generator protection standard.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
We Energies	No – Revise the design parameter as noted in the comments	This design parameter should be revised to clearly indicate that the base value of the per unit frequency component of the Volts per Hz ratio is 60 Hz to avoid any confusion with the scheduled frequencies that are used for time error correction (e.g. 59.98 or 60.02 Hz). **Response:** The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. We expect that all design simulations will be performed at a base frequency of 60 Hz. In addition, since the values listed in this design parameter are commonly used for generator volts per hertz protection settings, perhaps the system limits should have slightly lower allowable times so the generators do not

Organization	Question 5	Question 5 Suggested Revisions:
		trip undesirably during this period. **Response:** The technical basis for the performance characteristics was developed through a review of relevant industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. The SDT modified Characteristic 4.4 (Requirement R6.4) to further specify the location (Requirements R6.4.1 and R6.4.2).
Florida Power & Light Co.	No – Revise the design parameter as noted in the comments	Replace the words Bulk Electric System voltage with generator terminal voltage. The volts per hertz limits contained in 4.4 correspond to recommendations typical for generators. The temporary overvoltages (TOV) that will follow islanding with UFLS action tend to be significantly higher on the EHV transmission system since generators will be absorbing Vars and pulling voltage down. The EHV TOV capabilities are generally much higher than generator V/Hz limits and may be more variable due to individual grid design practices regarding basic insulation level and lightning arrester ratings. **Response:** We agree that the buses for which this should apply should be determined according to volts per Hz limits on applicable equipment, etc. In addition, SDT clarifies that the requirement does not address overvoltage limits. The SDT modified Characteristic 4.4 (Requirement R6.4) to further specify the location (Requirements R6.4.1 and R6.4.2). The words at least 25% should be replaced with up to 25% for the reasons discussed above. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.
Progress Energy Carolinas, Inc.	No – Delete the design parameter	This requirement is very difficult to measure from a transmission system perspective. A volts per hertz requirement is more appropriate in a generator protection standard.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
Ameren	No – Delete the design parameter	We believe that a volts per hertz requirement is more appropriate in a standard that deals with generation protection issues.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to		

Organization	Question 5	Question 5 Suggested Revisions:
prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
Alliant Energy	No – Delete the design parameter	This a subjective performance criteria as modeling details such as load damping assumptions, inertia assumptions, and governor response assumption will all have considerable effect on performance. This type of performance objective is best evaluated and determined at the Regional level or some mechanism needs to be in place to allow aggressive load shedding programs some latitude on this. There are cases where overshoots above 61 Hz could be accepted for short periods. The type of units in the island also have to be considered. Hydro systems have fewer off-nominal frequency restrictions. **Response:** The UFLS program must be designed such that all interconnected systems will meet common performance characteristics. Common performance characteristics facilitate coordination between regions. The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The 30 second time limit for operating above 60.5 Hz is not at all appropriate. Units can operate continuously at 60.5 Hz with no accelerated loss of life. They can run slightly above this for a long time. Could this be a typo? Was the intention to establish at 30 minute limit? **Response:** Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that are developing generator requirements (PRC-024).
E.ON U.S.	No – Revise the design parameter as noted in the comments	See Response to Question 9.
Response: Please see our response to your comment to Question 9.		
Manitoba Hydro	No – Revise the design parameter as noted in the comments	Again, Manitoba Hydro echo's the MRO's concerns. Each region should determine the volts per Hz based on its system topology, how it was planned and designed and the region's requirements.
Response: The UFLS program must be designed such that all interconnected systems will meet common performance characteristics. Common performance		

Organization	Question 5	Question 5 Suggested Revisions:
characteristics facilitate coordination between regions. The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
PacifiCorp	No – Revise the design parameter as noted in the comments	No issues related to the 1.18 V/Hz proposed requirement. The existing PacifiCorp standard overexcitation trip characteristic follows an inverse time characteristic for values over 1.08 V/Hz. The curve is set to protect a thermal unit per the manufacturer's recommendation. A typical curve will initiate a unit trip if the overexcitation value is 1.10 V/Hz for 291 seconds (4 min 51 seconds) a time delay that is more conservative than the manufacturer's recommendation. Overexcitation values are not typically accumulated. Protective relays implemented to protect the thermal fleet at PacifiCorp to not accumulate Volts/Hertz values. If the overexcitation element starts timing, then drops out, and once again starts timing the initial overexcitation event does not lower the trip time for the second event. ?????
Response: It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping. The SDT acknowledges that the PacifiCorp V/Hz protection application is more conservative than the proposed performance characteristic (Requirement R6.4).		
Transmission Reliability Program	No – Revise the design parameter as noted in the comments	Both question #5 above and the third bullet on page 3 of the summary document (starting with Bulk Electric System voltage . . . .) appear to be inconsistent regarding the "time durations" in the standard's characteristics section 4.4. Section 4.4 states: Control Bulk Electric System voltage during and following UFLS operations such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than "two seconds" cumulatively, and does not exceed 1.10 for longer than "45 seconds" cumulatively. The language in question #5 above respectively references 6 seconds cumulatively and 1 minute cumulatively. Based on the discussion on page 3, the shorter timeframes shown in section 4.4 are the correct values.
Response: Performance characteristic 4.4 states: Control voltage during and following UFLS operations such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than two seconds cumulatively, and does not exceed 1.10 for longer than 45 seconds cumulatively. The comment form does not reflect the characteristic but should have. This was an oversight.		
CenterPoint Energy	No – Delete the design parameter	As stated previously, CenterPoint Energy believes this effort should be postponed. Alternatively, this proposed design parameter should be deleted until coordination with the PRC-024 drafting team can be firmly established. If the design parameter is not deleted, CenterPoint Energy believes the proposed values are adequate to place proper balance and emphasis on system reliability as system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions.
Response: While the Project 2007-09 – Generator Verification (PRC-024) standard drafting team is addressing generator tripping requirements for off-nominal frequency and voltage, they are not explicitly addressing V/Hz protection. This performance characteristic (Requirement R6.4) is based on applicable IEEE		

Organization	Question 5	Question 5 Suggested Revisions:
standards and need not be delayed or deleted to allow coordination with the Generator Verification SDT.		
FirstEnergy Corp.	No – Delete the design parameter	1. When using the term "cumulatively" in this characteristic, when is the accumulation timer reset: a minute, an hour, a year? We are not clear if this is based on a design parameter or an "after-the-fact" performance review. We ask the SDT to provide clarification on this term. **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. 2. We recommend that this design parameter be deleted. The intent appears to be an attempt to prevent the overexcitation of generators and, to a lesser degree, transformers. It would be very difficult for entities responsible for setting UFLS equipment to conceive of every imbalance condition and prevent the possibility of any localized generator overexcitation to occur. These design parameters would be more appropriately addressed in generation protection standards to assure that generating units that can have impact on the frequency of the bulk electric system utilize proper overexcitation protection. **Response:** It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.
American Transmission Company	No – Revise the design parameter as noted in the comments	With respect to the 25 percentage (Characteristic 4), refer to comments for Question 2. **Response:** See response to question 2. With respect to the 6-second or 1-minute V/Hz values (Characteristic 4.4), the basis for these values has not been well established. In addition, for some potential islands the appropriate volt/hertz limits might vary based on the composition of generators and transformers in the island. Absolute continent-wide values may not be appropriate. The Characteristics could require that the proper voltage/hertz limits be investigated and established for each potential island. The proper V/Hz limits should be re-examined and changed, if necessary, whenever a generator or transformer is added or removed for a potential island and may potentially change the limits. **Response:** The technical basis for the performance characteristics was developed through a review of relevant industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. The

Organization	Question 5	Question 5 Suggested Revisions:
		SDT included more details regarding the technical justification for the performance characteristics in the comment form background (including specific IEEE standards). The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. The SDT considers that continent-wide limits are appropriate and that the performance characteristic is achievable and a necessary requirement. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of an interconnection.
Indiana Municipal Power Agency	No – Revise the design parameter as noted in the comments	The term cumulatively is confusing. It either needs to be clarified or removed. A clarification is needed on the per unit Volts per Hz relay protection. Is this relay protecting a generator step up transformer or a transmission/distribution transformer? If it covers the generator step-up transformer, then this item should not be covered in NERC PRC-024 standard and not in a regional standard.
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. It is not the purpose of this standard to set generator volts per Hz requirements, but to ensure that the UFLS program operation does not result in generator volts per Hz tripping. The SDT modified Characteristic 4.4 (Requirement R6.4) to further specify the location (Requirements R6.4.1 and R6.4.2).		
Duke Energy	No – Delete the design parameter	Delete or at least revise this characteristic. Volts per hertz is not typically monitored or limited on the power system itself. It is more of a concern with regard to equipment protection. This would be a difficult requirement to measure with the current modeling software (and modeling tools). If voltage following an event is the concern, then a requirement for voltage (only) should be stated. The limits in item 4 above should be sufficient to define performance for frequency. It is not clear why a voltage requirement is required since the transmission system must be operated within stated voltage limits regardless. Again, if voltage or issues like tripping capacitors are a concern, it should be stated differently.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
Georgia Transmission Corporation	No – Delete the design parameter	This requirement would be better served in the generator protection standard.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to		

Organization	Question 5	Question 5 Suggested Revisions:
prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
Entergy	No – Delete the design parameter	We agree with and support the SERC comments.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
PPL Generation	Yes	UFLS scheme should adhere to the IEEE standards for machines.
NPCC	Yes	
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	
Independent Electricity System Operator	Yes	

6. If there are any other characteristics in the UFLS Regional Reliability Standard Characteristics document that you disagree with, please identify them here, and either identify that they should be deleted, or recommend an alternative.

Summary Consideration:

The Underfrequency Load Shedding drafting team reviewed responses to this question and based on these comments made several conforming and/or clarifying changes to the performance characteristics (now Requirements).

- Several comments raised concerns that the "UFLS Regional Reliability Standard Characteristics" did not assign responsibility for specific requirements, instead leaving this to the regional standard development process. The SDT believes these concerns are addressed by the SDT deciding to convert the "UFLS Regional Reliability Standard Characteristics" into a continent-wide standard, which required the SDT to assign responsibility for each requirement.

- Several comments suggested that the database should be updated annually for consistency with the annual certification of the amount of load expected to be shed, and to ensure up-to-date data is available for analysis of system events. Other comments questioned whether the certification of amount of load expected to be shed is a measure of compliance rather than a requirement. The SDT agreed with these comments and revised the performance characteristic (Requirement R8) to require annual updates of the database. The SDT also removed the annual certification noting this obligation is effectively addressed by Requirements R9 (annual database updates) and R10 (provide load tripping in accordance with the UFLS program design). The measures by which compliance with these Requirements will be assessed will be defined in the Measures section of the proposed standard.

- Several comments expressed concern with the requirement to identify potential islands, noting this may be difficult if not impossible in tightly integrated systems, that other means than system studies or actual system operations should be permitted and that additional specificity should be provided as to the criteria for identification of islands. The SDT acknowledges the potential difficulty in interconnected systems, but noted that it is important that potential islands studied are based on physical characteristics of the system. The SDT clarified requirements concerning identification of islands in Requirements R3, R4, and R5, including provisions to include "any other islands necessary to ensure that all portions of the region's Bulk Electric System are included in at least one island." The SDT declined to prescribe a methodology for identifying islands, noting that unique physical characteristics of regions across the continent resist attempts to define common criteria.

- One comment indicated that the term "cumulative" should be removed from the overexcitation limits. The SDT believes the cumulative reference in performance characteristic 4.4 (Requirement R6.4) is appropriate. If during an islanding event the excitation on a transformer or generator exceeded 1.18 pu for an extended period of time, it would be inappropriate to reset the time requirement following a brief decline below 1.18 pu. The SDT has revised performance characteristic 4 to clarify the intent that these cumulative limits apply for each simulated event; not cumulatively for all actual system events.

Several responses to this question reiterate concerns regarding coordination with the PRC-024 drafting team expressed in prior questions. The SDT clarifies that it coordinated with the PRC-024 Generator Verification Standard Drafting Team by providing the generator tripping curves to ensure that the performance characteristics do not conflict with the generator tripping curves.

Several responses to this question reiterate concerns regarding the 25% imbalance (at system peak) expressed in prior questions. The SDT clarifies that the 25% represents the imbalance between load and generation not the amount of load at system peak to be shed. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.

- Some responses to this question reiterate concerns expressed in prior questions that it is more appropriate for the Planning Coordinators associated with the individual regions/islands to determine appropriate design values, while still coordinating with other regions/islands. These responses indicated that most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. The SDT clarifies that the performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard.

Organization	Question 6	Question 6 Suggested Revisions:
NPCC	Disagree with one or more of the characteristics as noted in the comments	We believe that characteristic 8 in the "UFLS Regional Reliability Standard Characteristics" should require database updates on an annual basis consistent with the requirement for annual certification of the amount of load expected to be shed in characteristic 11. Up-to-date data is a necessary requirement for analysis of system events.
Response: The SDT has revised characteristic 8 (Requirement R9) to require entities to provide data annually in order to ensure that up-to-date data is available when required for post-event analysis of system disturbances. The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. This is intended to eliminate the confusion regarding characteristic 11.		
Grand River Dam Authority	Disagree with one or more of the characteristics as noted in the comments	In part 5 and 6 there is reference to PRC-024. I could not find this. Should it be mentioned now or should it wait until it is available?
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the references to PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 (Requirement R6) will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
ERCOT	Disagree with one or more of the characteristics as noted in the comments	Regarding characteristic item 6, we believe it should only apply for Generator(s) that a Region have exempted from being compliant with PRC-024 and hence are aware of the impact on the UFLS effectiveness. The current wording suggests that the UFLS should compensate for any Generator(s) whenever they are non-compliant with PRC-024. Suggested wording be changed to: Item 6. If the Region has exempted any generators from the underfrequency tripping requirements of PRC-024, the Standard shall specify how such generators shall avoid

Organization	Question 6	Question 6 Suggested Revisions:
		jeopardizing UFLS effectiveness, or how entities responsible for designing UFLS shall compensate for any such non-compliant generators in their area to avoid jeopardizing UFLS effectiveness. The Standard shall require modeling of these method(s) in the UFLS assessment specified in item 10 below to ensure UFLS effectiveness is not jeopardized.
Response: The intent of characteristic 6 is to prevent generators from jeopardizing performance of the UFLS programs during underfrequency events. This can only be accomplished if all generators, regardless of whether they are exempted from or non-compliant with PRC-024, are correctly modeled and accounted during the design of UFLS programs. The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
American Electric Power (AEP)	Disagree with one or more of the characteristics as noted in the comments	
Response: The SDT requires more information on your concern to be responsive to your concern.		
PPL Generation	Disagree with one or more of the characteristics as noted in the comments	Comments on Items 2 and 3: Determination of "potential islands" may be difficult, if not impossible, to determine for tightly integrated electrical systems. **Response:** The SDT agrees that identification of potential islands required in characteristic 2 may be difficult in tightly interconnected systems. However, it is important that the potential islands studied are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analyses used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5. Comments on Item 4: As noted earlier, the characteristics proposed should be used as a guideline with provisions for deviation from the guidelines if mis-coordination existing between the UFLS program and legacy generating facilities. **Response:** The SDT does not agree that the characteristics should be guidelines. Any miscoordination between the UFLS program and legacy generating facilities can be addressed through modifications to the UFLS programs such as percent load drop or frequency threshold settings. The SDT has limited the performance requirements to addressing those aspects of the design and implementation that have a direct impact on reliability. Common performance requirements such as those provided in performance characteristic 4 (Requirement R6) are necessary to achieve coordination of UFLS programs.

Organization	Question 6	Question 6 Suggested Revisions:
		Comments on Items 5 and 6: Because PRC-024 is not available for review; it is not clear how these characteristics are related to the standard and how the generator or the entity responsible for the UFLS program is to comply. **Response:** The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The combined performance requirement characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz, and at or below 61.8 Hz. Comments on Item 9: PPL Corporation suggests identifying a responsible entity very early in the standard drafting process. Failure to do so can make the standard approval process more difficult. Further, identifying the responsible entities early can help in ensuring a better product in the end. **Response:** The SDT agrees with the comment on characteristic 9. The SDT has assigned the Transmission Owner and Distribution Provider this responsibility in the proposed standard (Requirement R10). Comments on Item 10: PPL Corporation suggests that the Regional Entity be identified as the responsible party. This would be consistent with the SDT's recommendation that the Regional Entity author the standard. If the Regional Entity delegates the responsibility, a separate agreement should be developed to accomplish this rather than rather than including the agreement in the standard. **Response:** The SDT believes it is not necessary to assign responsibility for characteristic 10 to the Regional Entity in order to ensure system reliability. The SDT recognizes that NERC standards should not be applicable to Regional Entities and has assigned the Planning Coordinators within a region this responsibility in the proposed standard (Requirement R7). Comments on Item 11: The text of this characteristic is confusing. PPL Corporation suggests clarifying wording of the characteristic and clearly identify what is it be certified annually, i.e. amount (MW) of load to be shed if that is what the SDT intended. **Response:** The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. This is

Organization	Question 6	Question 6 Suggested Revisions:
		intended to eliminate the confusion regarding characteristic 11.
Southwest Power Pool	Disagree with one or more of the characteristics as noted in the comments	If PRC-024 hasn't been developed as an enforceable standard, how do we know that we can comply with Characteristics 5 and 6?
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Bandera Electric Cooperative	Disagree with one or more of the characteristics as noted in the comments	The TRE UFLS SDT believes that the requirement that frequency shall not remain below 59.5 Hz for greater than 30 seconds would require a change in the existing ERCOT UFLS program Step 1 (59.3 Hz). The halfway-point between 60 Hz (normal) and 58.5 Hz (10 second minimum) is 59.25 Hz. **Response:** Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics. Frequency overshoot can be planned for by providing numerous steps of UFLS to avoid the overshoot. This should be fine for a gradual decay of frequency. However, during a large drop in frequency, all steps will operate simultaneously causing a possible overshoot. What can be done to reduce frequency at this point? **Response:** The SDT assumes that this condition would occur for a generation deficiency greater than 25%. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. For an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The SDT does not believe that the scenario mentioned by the commenter would lead to a frequency overshoot because the simultaneous operation of all steps would only occur if the imbalance exceeded the program capability. BEC voltage during and following UFLS operations shall be controlled not to exceed 1.18 for longer than 6 seconds cumulatively and 1.10 for longer than 1 minute cumulatively. Who should be responsible for non-compliance? Can this standard be enforced? **Response:** The SDT intended that performance characteristic 4 would apply only to the design of the UFLS

Organization	Question 6	Question 6 Suggested Revisions:
		program; not to post-event analysis of actual system events. As such the entity responsible for the design of the UFLS program will be responsible for demonstrating compliance with this performance characteristic under simulated conditions. The SDT believes this performance characteristic is enforceable as a UFLS program design requirement. The SDT has revised the language in characteristic 4 (Requirement R6) to better reflect our intent.
Midwest ISO	Disagree with one or more of the characteristics as noted in the comments	Item 5 references standard PRC-024. This standard should be vetted with these characteristics. Item 6 should not use the term non-compliant. A standard and its associated requirements are expected to be complied with. We suggest replacing item 6 with "The standard shall require taking into account the effect of generator underfrequency trip set points."
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Southern Company Services, Inc	Disagree with one or more of the characteristics as noted in the comments	Requirement 6 of the characteristics states the following: "The Standard shall specify how generators that are non-compliant with the PRC-024 underfrequency tripping requirement shall avoid jeopardizing UFLS effectiveness, or how entities responsible for designing UFLS shall compensate for any non-compliant generators in their area to avoid jeopardizing UFLS effectiveness. The Standard shall require modeling of these method(s) in the UFLS assessment specified in item 10 below to ensure UFLS effectiveness is not jeopardized." Is this requirement too open-ended for the responsible entity to have to "compensate" for non-compliant generators or does this approach give the responsible entity adequate flexibility to design mitigation plans into its methodologies? This seems to imply that (1) the non-compliant generators have already been identified and (2) that the responsible entity (not the non-compliant generator) shall be held responsible if mitigation plans are insufficient. We feel that Requirement 6 needs to avoid the use of the term "non-compliant" and instead focus on modeling actual generator trip points. We propose replacing Requirement 6 with the following: "The standard shall require taking into account the effect of generator underfrequency trip set points." The requirement, as originally written, is more appropriate in a generator protection standard. Non-compliance with PRC-024 should be addressed within PRC-024. Requirement 5 should be deleted since it is redundant with Requirement 4. Requirement 4.1, 4.2 and 4.3 should be re-worded to establish coordination with PRC-024 in each of the areas shown. As written, we feel there is a possibility of creating a double jeopardy situation with what may be written into the requirements of PRC-024.
Response: The SDT agrees. The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet		

Organization	Question 6	Question 6 Suggested Revisions:
characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
PJM	Disagree with one or more of the characteristics as noted in the comments	Delete Items 8 and 9 - should be handled in the Functional Model.
Response: The NERC Functional Model defines the reliability functions required for maintaining electric system reliability so that organizations involved in ensuring reliability can identify those functions they perform, and register with NERC as one or more of the Responsible Entities. The Functional Model is not intended to contain the level of specificity necessary to identify what entities are responsible for specific requirements of reliability standards. The SDT believes it is appropriate for standards to identify the entities responsible for providing data for database maintenance (characteristic 8, now Requirement R9) and owning, installing, and setting UFLS equipment (characteristic 9, now Requirement R10). The SDT has assigned the Transmission Owner and Distribution Provider these responsibilities in the proposed standard.		
Florida Reliability Coordinating Council	Disagree with one or more of the characteristics as noted in the comments	The characteristics should specify design criteria of the UFLS Programs and should not be confused with the actual system performance following an underfrequency condition. The UFLS Program should be developed to meet the design characteristics with the understanding that system performance will be dependent on the current system conditions and could potentially not meet the design characteristics of the program. Bullet No. 4 of the characteristics should read, "The Standard shall require that the UFLS Program be developed incorporating the following design characteristics?"
Response: The SDT intended that characteristic 4 (Requirement R6) would apply only to the design of the UFLS program; not to post-event analysis of actual system events. The SDT has revised the language in the proposed standard to better reflect our intent.		
Southern Company Services, Inc. – Trans	Disagree with one or more of the characteristics as noted in the comments	In addition to the above comments, requirement #6 need to avoid use of the term "non compliant" and instead focus on modeling actual generator trip points. Propose replacing # 6 with the following: "The standard shall require taking into account the effect of generator underfrequency trip set points." Requirement 5 should be deleted since it is redundant with Requirement 4.
Response: The SDT agrees. The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		

Organization	Question 6	Question 6 Suggested Revisions:
Northeast Utilities	Disagree with one or more of the characteristics as noted in the comments	Section 10.2 of the draft characteristics requires an assessment be conducted every 5 years. Based on experience, the schedule for a given analysis can drag beyond a deadline when there is difficulty in achieving convergence of study results, or modeling problems. There should be some accommodation in the Standard to account for these schedule overruns.
Response: The SDT recognizes the complexity involved with UFLS design. Developing the process for complying with performance characteristic 10.2 (Requirement R7) is left to the Planning Coordinators in each region. Re-assessment of the design, to be done at least every 5 years thereafter the original design, will be accomplished with the advantage of foreknowledge of the complexity and time involved in the initial UFLS program design. The Planning Coordinators must take this into account when developing their process for scheduling the UFLS design re-assessment.		
We Energies	Disagree with one or more of the characteristics as noted in the comments	Please see comments associated with question 5.
Response: Please see responses to comments associated with question 5.		
Florida Power & Light Co.	Disagree with one or more of the characteristics as noted in the comments	The design of a coordinated underfrequency load shedding program is primarily a planning activity that is based on analysis of potential islanding scenarios. With the exceptions noted above, it is reasonable to expect that a UFLS program's technical design parameters will meet the electrical design requirements identified in item four of the UFLS Regional Reliability Standard Characteristics for a load mismatch of 25%. Meeting these frequency and voltage design limits becomes increasingly difficult with higher load mismatch scenarios. The UFLS Regional Reliability Standard Characteristics as currently drafted implies the performance requirements should be applicable to both planned contingency scenarios and to actual performance during frequency excursions. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of at least 25% will meet the frequency and voltage performance requirements. Applying these requirements to actual disturbance events is inappropriate because of the large number of possible scenarios that may lead to frequency excursions. **Response:** The SDT agrees with the comment that meeting the proposed performance characteristics would become increasingly difficult for generation imbalances exceeding 25 percent. The SDT intended that compliance would not be required for an imbalance greater than 25% and has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/(load) of up to 25 percent within the identified island. For an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

Organization	Question 6	Question 6 Suggested Revisions:
		It is possible that an actual system islanding event occurs through a complex combination of multiple outages and adverse operating conditions that are impossible to predict. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of 25% will meet the frequency and voltage performance requirements. Accordingly, the words or actual system conditions should be removed from item 2 in the UFLS Regional Reliability Standard Characteristics. **Response:** The SDT intended that performance characteristic 2 would apply only to design of the UFLS program; not to post-event analysis of actual system events. However, it is important that the potential islands studied are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analyses used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5. Item 5 in the UFLS Regional Reliability Standard Characteristics as currently worded would prevent the use of additional layers of backup UFLS protection. The FRCC requires 9 UFLS steps be armed with a total of 56% of planned peak load. Some of these steps provide time delayed backup levels of protection in case frequency stabilizes at a level below 59.7 hertz or in case unplanned generator trips occur. In the event an island formed with a 50% load mismatch, it is likely frequency would go below 57.0 hertz and that generator tripping would occur before these time delayed backup steps would have a chance to operate. The words by requiring that UFLS programs complete execution before generators begin to trip on underfrequency should be removed from item 5 in the UFLS Regional Reliability Standard Characteristics. **Response:** As stated above, Regional Entities may, if they choose, develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedures for an imbalance exceeding 25%. The SDT has decided to revise and combine characteristics 5 and 6. In doing so, the words “by requiring that UFLS programs complete execution before generators begin to trip on underfrequency” have been removed from the combined characteristic (Requirement R7).
Exelon	Disagree with one or more of the characteristics as noted in the comments	Requirement 9 should specify the criteria used to determine an island subject to this standard. **Response:** Performance characteristic 2 (Requirement R5) does not provide criteria for determining potential islands; however, provides guidance that potential islands studied are based on physical characteristics of the system which can be identified through historical events or system studies, such as analysis used to identify coherent groups of generation, limited number of transmission connections, limited transfer capability, etc. Regions across the continent have unique physical characteristics that resist attempts to define common criteria to determine islands.

Organization	Question 6	Question 6 Suggested Revisions:
		Requirements 1 and 2 should specify which entities are responsible for determining what load is responsible for meeting the UFLS performance requirements of R4. Requirement 3 should specify which entities will ensure coordination across intra and inter-Regional boundaries. This should be consistent across the continent. **Response:** The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and has assigned responsibility for these requirements within the proposed standard. Requirement 5 and 6 should not address specific Standards, as it is unclear how this document could be updated if particular Standards were added, revised, or deleted which affect the Requirements included here. Requirement 6 is confusing - is non-compliance with portions of PRC-024 allowed through mechanisms alluded to here? **Response:** The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz. Requirements 7, 8, 9 and 10 should specify which entities are to maintain a data base, which entities are to maintain the data base and determine required parameters, which entities are responsible for owning, installing, and setting UFLS equipment, and which entities are responsible for performing UFLS assessments, respectively. **Response:** The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and has assigned responsibility for these requirements within the proposed standard.
Progress Energy Carolinas, Inc.	Disagree with one or more of the characteristics as noted in the comments	In addition to the above comments, NERC Characteristic #6 needs to avoid use of the term "non compliant" and instead focus on modeling actual generator trip points. Propose replacing Characteristic # 6 with the following: "The standard shall require taking into account the effect of generator underfrequency trip set points." Characteristic #5 should be deleted since implementation of Characteristic #4 should achieve this objective (i.e. Characteristic #5 is redundant).
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations		

Organization	Question 6	Question 6 Suggested Revisions:
performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Ameren	Disagree with one or more of the characteristics as noted in the comments	Regarding Item #7, we believe that the Regional Entity should maintain the database to provide uniformity and consistency. Regarding Item #9, the Standard which specifies who owns, install, or sets UFLS equipment should accommodate existing practices. For example, in some organizations, DP actually sheds the load to remedy a GO/TO system-wide event and the standard should ensure that these practices will be allowed to continue. Regarding Item #10, the regional entity should be responsible for performing the assessment or having an assessment performed.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and has assigned responsibility for characteristic 7 (Requirement R8) and characteristic 10 (Requirement R7) to the Planning Coordinators within each Region. The SDT recognizes that NERC standards should not be applicable to Regional Entities. The SDT agrees that existing practices should be accommodated where possible. The Planning Coordinators may define the UFLS program in a manner that accommodates existing practices with respect to shedding load. Regarding characteristic 9 (Requirement R10), Transmission Owners and Distribution Providers have been assigned responsibility in the continent-wide standard.		
Alliant Energy	Disagree with one or more of the characteristics as noted in the comments	The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard. The MRO would ask that characteristics 5 and 6 remove the reference to PRC-024, but do agree with the need for coordination between UFLS and generation protection and expressing the characteristics 5 and 6 in more general terms. **Response:** The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below

Organization	Question 6	Question 6 Suggested Revisions:
		61.8 Hz.
E.ON U.S.	Disagree with one or more of the characteristics as noted in the comments	See Response to Question 9.
Response: Please see our response to your comment to Question 9.		
Manitoba Hydro	Disagree with one or more of the characteristics as noted in the comments	#8 requires entities to provide data at least every 5 years to support the UFLS database. #11 requires responsible entities to certify annually that the load it expects to shed will result in frequency excursions below the initializing set points of the regional UFLS standard. How can the responsible entity certify this, when the database, and therefore modeled conditions, may be 4 years out of date? Entities should be required to provide data annually to the UFLS, even if it is a "no change" ascertained.
Response: The SDT has revised characteristic 8 (Requirement R9) to require entities to provide data annually in order to ensure that up-to-date data is available when required for post-event analysis of system disturbances. The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. This is intended to eliminate the confusion regarding characteristic 11.		
PacifiCorp	Disagree with one or more of the characteristics as noted in the comments	Remove the requirement that the over excitation element be cumulative.
Response: The SDT believes the cumulative reference in performance characteristic 4.4 (Requirement R6.4) is appropriate. If during an islanding event the excitation on a transformer or generator exceeded 1.18 pu for an extended period of time, it would be inappropriate to reset the time requirement following a brief decline below 1.18 pu. The SDT has revised performance characteristic 4 to clarify the intent that these cumulative limits apply for each simulated event; not cumulatively for all actual system events.		
CenterPoint Energy	Disagree with one or more of the characteristics as noted in the comments	Characteristic Item 11 proposes that a UFLS regional standard include a requirement that owners of UFLS equipment must certify, on an annual basis, the amount of load it expects to shed in an underfrequency event. CenterPoint Energy concurs that some type of annual mechanism is warranted to "measure" whether the required load will be shed within a particular region, as UFLS is a critical safety net for the Bulk Power System - providing a last resort function. However, it would be expected that a UFLS regional standard would include the percentages of load to be shed as a Requirement. Therefore, CenterPoint Energy recommends that Characteristic Item 11 be deleted as a Requirement. CenterPoint Energy believes that a Requirement is not the appropriate vehicle to prescribe the type of compliance mechanism (e.g. certification, surveys, assessments), nor

Organization	Question 6	Question 6 Suggested Revisions:
		the frequency (e.g., annually) of the compliance check. These types of compliance items should be determined through the regional standard development process.
Response: The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. The SDT has revised characteristic 9 (Requirement R10) to specify that "Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which they operate." The measure by which compliance with the Requirement will be assessed will be defined in the Measures section of the proposed standard.		
FirstEnergy Corp.	Disagree with one or more of the characteristics as noted in the comments	Characteristics #5 and #6 - It is difficult to determine the acceptability of these characteristics since industry has not yet seen a draft of PRC-024 (Generator Performance During Frequency and Voltage Excursions). Completion of the development of these characteristics and coordination of these characteristics with the proposed requirements of PRC-024 cannot be finalized until the PRC-024 has been fully vetted through industry and approved by NERC and FERC.
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
American Transmission Company	Disagree with one or more of the characteristics as noted in the comments	The references to the PRC-024 standard should be removed and the desired characteristic restated in more general terms.
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Indiana Municipal Power Agency	Disagree with one or more of the characteristics as noted in the comments	A characteristic needs to be added to allow exemptions for equipment that might not be able to meet these under frequency characteristics or the Volts per Hz settings. Some equipment relay protection may not be able to be changed due to OEM limitations which need to be properly protected to prevent equipment damage. If an entity can provide the technical documentation to back up this OEM limitation and notifies the transmission planner, then an exemption should be allowed and not force an entity to be non-compliant.
Response: The proposed performance characteristics do not create any requirements that prohibit proper protection of equipment. The SDT does agree that		

Organization	Question 6	Question 6 Suggested Revisions:
equipment limitations should be addressed in any PRC standard that establishes protective relay setting requirements.		
Duke Energy	Disagree with one or more of the characteristics as noted in the comments	Disagreements are noted in the responses above. Additionally, -- Recommend deleting Requirement 5 since it is redundant with Requirement 4.-- Requirement 6 should avoid use of the term "non compliant". Compliance, and consequently non-compliance, should be handled in PRC-024 itself. If the goal is to verify the UFLS scheme while considering generation trip setpoints, then this requirement should focus on modeling the generation trip setpoints. Propose replacing Requirement 6 with the following: "The standard shall require generator underfrequency tripping be included in the UFLS assessment specified in item 10 below."-- **Response:** The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz. Requirement 2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording should be changed so that islands can be identified as appropriate and not just by system studies or actual system operations. For systems that have not experienced islanding events and where system studies have not shown islands, this would be difficult to meet. Recommend changing the requirement to read, "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." **Response:** Performance characteristic 2 (Requirement R5) has been revised so that islands may include “those islands selected by applying the criteria in Requirement 3, if any” (which considers historical events and system studies) and “any other islands necessary to ensure that all portions of the region’s Bulk Electric System are included in at least one island.”
Georgia Transmission Corporation	Disagree with one or more of the characteristics as noted in the comments	Requirement #6 needs to avoid the use of the term "non compliant" and instead focus on modeling actual generator trip points
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate		

Organization	Question 6	Question 6 Suggested Revisions:
with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Entergy	Disagree with one or more of the characteristics as noted in the comments	We agree with and support the SERC comments.
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Southwest Power Pool	Disagree with one or more of the characteristics as noted in the comments	Since PRC-024 is not a currently enforceable standard, we can not concur with Characteristics 5 and 6.
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Transmission Reliability Program	Agree with all proposed characteristics	
Independent Electricity System Operator	Agree with all proposed characteristics	
Buckeye Power, Inc.	Agree with all proposed characteristics	
Louisiana Generqting, LLC	Agree with all proposed characteristics	
City Water, Light	Agree with all proposed	

Organization	Question 6	Question 6 Suggested Revisions:
& Power - Springfield, IL	characteristics	

7. The SDT proposes that the regional standards include the database requirements contained in existing Reliability Standard PRC-007. Do you agree that database requirements should be addressed within the Regional Standards?

Summary Consideration:

The responses to this question support the requirement for regional databases. The SDT has retained the regional aspect of the database requirement within the proposed continent-wide standard by assigning responsibility to the group of Planning Coordinators in each region to create and maintain a database containing relay information needed for assessments and event analysis (Requirement R8).

Several comments suggested that a common format for the database be established. The SDT believes that a variety of formats could serve reliability equally well and as such the SDT does not feel compelled to specify a format in the proposed continent-wide standard. The group of Planning Coordinators in each region has been assigned the responsibility for assessments of the UFLS program in the proposed continent-wide standard and is therefore best suited to identify the program database format.

Some comments suggested that the database should be updated annually, reiterating concerns expressed in responses to prior questions. The SDT agreed with these comments and revised the performance characteristic (Requirement R8) to require annual updates of the database.

One comment suggested including requirements for archiving the regional UFLS data. The SDT will address archiving requirements in the Data Retention section of the proposed standard.

Organization	Question 7	Question 7 Suggested Revisions:
Exelon	No	It would be helpful for inter-Regional coordination studies to have a common set of database requirements. Why not specify them here to ensure that this is standardized?
Response: The SDT expects that each regional UFLS database will need to contain the UFLS data items needed for UFLS assessments. While the approach proposed in the first posting would have allowed the regions to assign this responsibility, the SDT in the proposed standard has assigned the specification of database content to the Planning Coordinators in each region.		
E.ON U.S.	No	E.ON U.S. believes that database requirements should be established on a case-by-case basis. A database that tracks the dynamically changing system conditions under normal operation is not necessary. Only instances when an UF event occurs should be subject to a data retention requirement
Response: The SDT would like to clarify that the database contains UFLS program data; not event data.		
PPL Generation	Yes and No	PPL agrees that the database requirements should be addressed within the Regional Standard developed. However, the data requirements must be clearly identified. Further, the burden of providing such data in particular data formats (for study

Organization	Question 7	Question 7 Suggested Revisions:
		purposes) should not be delegated to the UFLS program owner - the Regional Entity performing the study should be responsible for data preparation and formatting.
Response: The SDT expects that each regional UFLS database will need to contain the UFLS data items needed for UFLS assessments. While the approach proposed in the first posting would have allowed the regions to assign this responsibility, the SDT in the proposed standard has assigned the specification of database content to the Planning Coordinators in each region. Any decisions on formatting requirements for data submittals by UFLS program owners are likewise reserved to the Planning Coordinators.		
Alliant Energy	Yes and No	The MRO agrees that any database requirements should be addressed within the Regional Standards. However, we hope that the database requirements among regions within the same Interconnection are the same. In addition, we would expect that the database would be required to be updated every year.
Response: The SDT expects that each regional UFLS database will need to contain the UFLS data items needed for UFLS assessments. While the approach proposed in the first posting would have allowed the regions to assign this responsibility, the SDT in the proposed standard has assigned the specification of database content to the Planning Coordinators in each region. A requirement for annual update of the regional UFLS databases has been added to the continent-wide standard (see Requirement R8).		
Bandera Electric Cooperative	Yes	The TRE UFLS SDT believes each regional UFLS program should include the requirement for archiving the region's UFLS data and that database should be available to entities within the region and should be part of the region's requirements constituting auditable compliance with the standard. The TRE UFLS SDT feels these databases are required to efficiently conduct the necessary studies. The regional standard should also clearly define the entity responsible/accountable for complying with the standard (equipment ownership, equipment maintenance, database maintenance, reporting, etc.) perhaps the RC or PA. Regardless of who is designated, that functional entity should be responsible for developing a database format/template to ensure UFLS data consistency and completeness as well as study efficiency.
Response: Under the continent-wide standard now being proposed, Planning Coordinators would be responsible for creating and maintaining a regional UFLS database. Archiving requirements will be covered in the Data Retention section of the proposed standard. The remaining points in this comment are consistent with the concept of regional standards in support of a continent-wide standard which the proposed continent-wide standard would allow.		
Southern Company Services, Inc	Yes	PRC-007 contains the specific requirement for ?documentation [to be provided for the] Regional Reliability Organization to maintain and update a UFLS program database.? PRC-006 specifies the design details to be addressed, such as frequency set points, time delays, etc. Some latitude is given to the regions in formulating the details of their UFLS programs and individual regional programs may differ to some extent. Therefore, in order to demonstrate that these region specific requirements are being meet, the database requirements will need to be included in the regional standards. Also, PRC-006 requires periodic dynamic simulations to assess the effectiveness of the UFLS program (ref. PRC-006 R1.4.2). Since different regions may have different requirements, the ability to obtain the necessary information to perform the required

Organization	Question 7	Question 7 Suggested Revisions:
		dynamic simulations (either on a regional basis or by individual entities), depends on being able to obtain the type of data that would reside in a UFLS program database. Including the database requirements within the Regional Standards will help ensure this is possible.
Response: Thank you for your support.		
SERC	Yes	PRC-007 contains the specific requirement for "documentation [to be provided for the] Regional Reliability Organization to maintain and update a UFLS program database." PRC-006 specifies the design details to be addressed, such as frequency setpoints, time delays, etc. Some latitude is given to the regions in formulating the details of their UFLS programs and individual regional programs may differ to some extent. Therefore, in order to demonstrate that these region specific requirements are being meet, the database requirements will need to be included in the regional standards. Also, PRC-006 requires periodic dynamic simulations to assess the effectiveness of the UFLS program (ref. PRC-006 R1.4.2). Since different regions may have different requirements, the ability to obtain the necessary information to perform the required dynamic simulations (either on a regional basis or by individual entities), depends on being able to obtain the type of data that would reside in a UFLS program database. Including the database requirements within the Regional Standards will help ensure this is possible.
Response: Thank you for your support.		
Buckeye Power, Inc.	Yes	Regional databases should have a common format and the database should have transparent coordination
Response: The SDT expects that each regional UFLS database will need to contain the UFLS data items needed for UFLS assessments. While the approach proposed in the first posting would have allowed the regions to assign this responsibility, the SDT in the proposed standard has assigned the specification of database content to the Planning Coordinators in each region. Any decisions on formatting requirements for data submittals by UFLS program owners are likewise reserved to the Planning Coordinators.		
Progress Energy Carolinas, Inc.	Yes	PRC-007 contains the specific requirement for "documentation [to be provided for the] Regional Reliability Organization to maintain and update a UFLS program database." PRC-006 specifies the design details to be addressed, such as frequency setpoints, time delays, etc. Some latitude is given to the regions in formulating the details of their UFLS programs and individual regional programs may differ to some extent. Therefore, in order to demonstrate that these region specific requirements are being meet, the database requirements will need to be included in the regional standards. Also, PRC-006 requires periodic dynamic simulations to assess the effectiveness of the UFLS program (ref. PRC-006 R1.4.2). Since different regions may have different requirements, the ability to obtain the necessary information to perform the required dynamic simulations (either on a regional basis or by individual entities), depends on being able to obtain the type of data that would reside in a UFLS program database. Including the database requirements within the Regional Standards will help

Organization	Question 7	Question 7 Suggested Revisions:
		ensure this is possible.
Response: Thank you for your support.		
American Transmission Company	Yes and No	ATC agrees that any database requirements should be addressed within the Regional Standards. However, we hope that the database requirements among regions within the same Interconnection are the same. In addition, we would expect that the database would be required to be updated every year.
Response: The SDT expects that each regional UFLS database will need to contain the UFLS data items needed for UFLS assessments. While the approach proposed in the first posting would have allowed the regions to assign this responsibility, the SDT in the proposed standard has assigned the specification of database content to the Planning Coordinators in each region. A requirement for annual update of the regional UFLS databases has been added to the continent-wide standard (see Requirement R8).		
Entergy	Yes	We agree with and support the SERC comments.
Response: Thank you for your support.		

8. Are you aware of any conflicts between the proposed regional standards and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

Summary Consideration:

The responses to this question did not identify any conflicts with regulatory functions, roles, orders, tariffs, rate schedules, legislative requirements, or agreements. Several comments suggested that state tariffs and OATT requirements need to be reviewed for potential conflicts, but no comments identified conflicts and it is not apparent to the SDT that any exist.

Some comments suggested potential confusion with existing programs or identifying responsibility for providing load shedding. The SDT believes these concerns are addressed in the continent-wide standard by assigning applicability to "Distribution Providers" and "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load." We believe this covers all load and eliminates potential confusion regarding Load Serving Entities.

One comment expressed concern with potential conflicts between PRC-006 and PRC-024 and recommended that development of PRC-006 be delayed until PRC-024 has been approved. The SDT believes that adequate coordination exists between the Generator Verification SDT developing PRC-024 and development of PRC-006. The SDT will continue to coordinate with the GVSDT and we believe it does not matter whether PRC-006 or PRC-024 is approved first as long as this coordination exists.

One comment expressed concern with potential conflicts with the draft Reliability First regional standard and legacy ECAR documents. The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

Organization	Question 8	Question 8 Suggested Revisions:
Southern Company Services, Inc	Yes	We are concerned that the Under-Frequency Load Shedding characteristics are being developed and finalized prior to the development of the Generator Verification Standard - PRC-024. Since regional standards must coordinate with PRC-024 it is only prudent that the UFLS Drafting Team and the Regions have knowledge of the approved version of PRC-024 before the Drafting Team/Standards Committee requires regions to coordinate with the Generation Verification Standard. Also, some OATT requirements may need to be adjusted to be consistent with regional requirements.
Response: The technical basis for the UFLS performance characteristics was developed through a review of relevant industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. In addition, the SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team (GV SDT) by providing the underfrequency performance curve to ensure that the performance characteristics do not conflict with the generator off nominal frequency capability curve. The GV SDT has posted the generator off nominal frequency capability curve for industry comment and the UFLSDT will continue to coordinate with the GV SDT on this item. The UFLSDT believes it does not		

Organization	Question 8	Question 8 Suggested Revisions:
matter whether PRC-006 or PRC-024 is approved first as long as this coordination exists. Thank you for your input and caution. Individual drafting team members are not aware of any conflicts and based on numerous comments there are not any apparent conflicts.		
FirstEnergy Corp.	Yes	We feel that the design parameters specified in characteristic #4 conflicts with the draft RFC standard and legacy ECAR document.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
Bandera Electric Cooperative	Yes and No	The TRE UFLS SDT believes there may potentially be a conflict. The ERCOT Power Region has customer choice of Retail Energy Providers (REP)/LSE. Although the standard appears to be written as permissible in not enforcing UFLS requirements on an LSE ("...and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization)...)", it might be construed that LSEs in ERCOT may be subject to the requirements under the standard as written. The TRE UFLS SDT also comments that the proposed standard does not address allocation to self-serve or large industrials. The TRE UFLS SDT believes that self-serve entities with load and generation connected to the grid should be addressed.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and has assigned applicability to "Distribution Providers" and "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load." We believe this covers all load and eliminates potential confusion regarding Load Serving Entities.		
PacifiCorp	Yes and No	Proposed regional standard should specify the responsibility for dropping loads that are not served by operator of the control area, such as power generated in another control area and then scheduled to serve distribution loads of another utility.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and has assigned applicability to "Distribution Providers" and "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load." We believe this covers all load.		
Entergy	No	We agree with and support the SERC comments.
Response: Thank you for your input and caution. Individual drafting team members are not aware of any conflicts and based on numerous comments there are not any apparent conflicts.		

Organization	Question 8	Question 8 Suggested Revisions:
American Electric Power (AEP)	No	All state tariffs need to be reviewed for conflicts.
Response: Thank you for your input and caution. Individual drafting team members are not aware of any conflicts and based on numerous comments there are not any apparent conflicts.		
SERC	No	Some OATT requirements may need to be adjusted to be consistent with regional requirements.
Response: Thank you for your input and caution. Individual drafting team members are not aware of any conflicts and based on numerous comments there are not any apparent conflicts.		
Progress Energy Carolinas, Inc.	No	Some OATT requirements may need to be adjusted to be consistent with regional requirements.
Response: Thank you for your input and caution. Individual drafting team members are not aware of any conflicts and based on numerous comments there are not any apparent conflicts.		
City Water, Light & Power - Springfield, IL	No	
NPCC	No	
Grand River Dam Authority	No	
ERCOT	No	
Florida Power & Light	No	
Southwest Power Pool	No	
Louisiana Generqting, LLC	No	
Midwest ISO	No	
PJM	No	

Organization	Question 8	Question 8 Suggested Revisions:
Florida Reliability Coordinating Council	No	
Buckeye Power, Inc.	No	
Northeast Utilities	No	
We Energies	No	
Exelon	No	
Ameren	No	
Alliant Energy	No	
E.ON U.S.	No	
Manitoba Hydro	No	
Transmission Reliability Program	No	
Independent Electricity System Operator	No	
CenterPoint Energy	No	
American Transmission Company	No	
Duke Energy	No	
Georgia Transmission Corporation	No	
Southwest Power Pool	No	

9. Do you have any other questions or concerns with the proposed Under Frequency Load Shedding Regional Reliability Standard Characteristics that have not been addressed? If yes, please explain.

Summary Consideration:

In general the responses to this question reiterate concerns expressed in responses to prior questions. A few new issues were raised in responses to this question.

- One comment suggested the need to manage automatic load restoration in concert with the UFLS program. The SDT agrees and has added a requirement (R7.3) in the proposed continent-wide standard to require modeling of automatic load restoration in the five year assessments performed by the group of Planning Coordinators in each region.
- Some comments expressed concern that requiring "dynamic simulations" to verify the UFLS program design was overly prescriptive and could be revised to "analytical studies." The SDT believes it is not possible to verify the adequacy of the implementation of the regional UFLS program in achieving the performance characteristics without some sort of dynamic simulation and has decided to retain this level of specificity.
- Some comments suggested the need for the standard to recognize coordination requirements with other frequency responsive load programs. The SDT believes the Planning Coordinators need to consider any such programs to ensure their implementation coordinates with the performance characteristics contained in the proposed continent-wide standard.

The remaining responses to this question reiterate concerns expressed in responses to prior questions.

- Several comments expressed concern with the requirement to identify potential islands, noting this may be difficult if not impossible in tightly integrated systems, that other means than system studies or actual system operations should be permitted, and that additional specificity should be provided as to the criteria for identification of islands. The SDT acknowledges the potential difficulty in interconnected systems, but noted that it is important that potential islands studied are based on physical characteristics of the system. The SDT clarified requirements concerning identification of islands in Requirements R3, R4, and R5, including provisions to include "any other islands necessary to ensure that all portions of the region's system are included in at least one island." The SDT declined to prescribe a methodology for identifying islands, noting that unique physical characteristics of regions across the continent resist attempts to define common criteria.
- Several responses to this question reiterate concerns regarding the 25% imbalance (at system peak) expressed in prior questions. The SDT clarifies that the 25% represents the imbalance between load and generation not the amount of load at system peak to be shed. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.
- Several responses to this question reiterate concerns regarding coordination with the PRC-024 standard drafting team expressed in prior questions. The SDT clarifies that it coordinated with the PRC-024 Generator Verification Standard Drafting Team by providing the generator tripping curves to ensure that the performance characteristics do not conflict with the generator tripping curves.
- Several comments raised concerns that the "UFLS Regional Reliability Standard Characteristics" did not assign responsibility for specific requirements, instead leaving this to the regional standard development process. The SDT believes these concerns are addressed by the

SDT deciding to convert the "UFLS Regional Reliability Standard Characteristics" into a continent-wide standard, which required the SDT to assign responsibility for each requirement.

- Several comments suggested that the database should be updated annually for consistency with the annual certification of the amount of load expected to be shed, and to ensure up-to-date data is available for analysis of system events. The SDT agreed with this comment and revised the performance characteristic (Requirement R8) to require annual updates of the database.
- Several comments suggested the need to clarify that compliance with the performance characteristics is demonstrated through design of the UFLS program rather than analysis of actual system events. The SDT agrees and has modified Requirement R6 in the proposed continent-wide standard to clarify this point.
- Some responses to this question indicate that it is more appropriate for the Planning Coordinators associated with the individual regions/islands to determine appropriate design values, while still coordinating with other regions/islands. These responses indicated that most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. The SDT clarifies that the performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard.

Organization	Question 9	Question 9 Suggested Revisions:
NPCC	Yes	We believe that the phrase "meet the following performance characteristics for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent" could be interpreted to require meeting the performance requirements for all generation deficiencies between 25 percent and 100 percent, instead of the intended 0 percent to 25 percent. We recommend that this phrase be revised as "meet the following performance characteristics for underfrequency conditions resulting from all imbalances between load and generation between 0 and 25 percent." We understand the intent of using the words "at least" may have been to recognize that regions may base their program on deficiencies greater than 25 percent; however, it is not necessary to provide within these characteristics that regions may exceed these requirements. The related NERC "Implementation Plan for Underfrequency Load Shedding Regional Reliability Standard Characteristics" must consider that some regional programs may require modification in order to meet these requirements. Accordingly, a time based implementation schedule should be developed with input from the Regional Drafting Teams once more detail surrounding the individual Regional Standards are known.
Response: The SDT agrees and has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The SDT agrees that there is a need for a time based implementation schedule. A future draft of the continent-wide standard will have an implementation plan that will consider modifications in order to meet these requirements.		

Organization	Question 9	Question 9 Suggested Revisions:
Florida Power & Light	Yes	This proposed standard references PRC -024 which is not yet an approved standard has not been released for comment, and does not seem to be available on the NERC website for review.
Response: The SDT has decided to revise and combine characteristics 5 and 6 (now covered by Requirement R7). In doing so, we have eliminated the references to PRC-024.		
PPL Generation	Yes	PPL agrees with the concept proposed by the SDT. However, unique problems can exist for generators not owned/operated by the host regulated TO/TSP. Such entities cannot make arrangements with "load" to mitigate a generator UF trip setting that may fall above the lowest setting of load UF trip settings. Generator manufacturers UF/OF trip points are extremely important and may be the independent variable in this equation. Generator owners/operators must respect the manufacturer's recommendations for the generator UF trip settings. Generator Owner/Operator shall provide the lowest plant underfrequency setting and basis for this setting to the TO/TSP and or BA/RC in order to ensure coordination with the load UF trip settings. It should also be understood that the lowest manufacturer setting of the generator may not be the driving UF setting that needs to be coordinated with the TO/TSP UFLS scheme of the transmission system. For example, a nuclear unit may have a reactor pump UF setting or the Reactor protective system both having UF relays that can result in a trip of the unit. In any event, the host TO/TOP/TSP/BA needs to coordinate the UFLS program settings with the generators most limiting UF trip settings. The Regional Entity, with input from TO/TSP and generators, should be responsible for ensuring such coordination exists.
Response: The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop. The SDT is proposing requiring the group of Planning Coordinators in each region to model the trip settings of generators that would trip at or above 58.0 Hz and at or below 61.8 Hz in Requirement R7. The Planning Coordinators would still need to show that their UFLS program design satisfies the performance characteristics in Requirement R6. Generator Owners have been removed from the applicability section of the proposed standard.		
Southwest Power Pool	Yes	Please include parameters that will address each region's approach conducting studies as requested in UFLS regional reliability standard characteristic. **Response:** The SDT needs more information regarding your concern to provide a response. > Is it acceptable for each region to assume that it is an island separate from neighboring region(s) when performing these studies even though during an actual event each region in Eastern Interconnect is interconnected to neighboring regions? **Response:** It is important that the potential islands studied are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analysis used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5.

Organization	Question 9	Question 9 Suggested Revisions:
		> There is a lot of wording in the questions in the Comment Form that states thing like: "must act", "does not exceed", "must arrest" This type of wording makes very rigid requirements and leaves little room for unplanned situations, mis-operations or acts of God. The wording needs to be modified to include the word "designed"; i.e. the system must be "designed" to act, must be "designed" to not exceed, and must be "designed" to arrest. This seems to apply we are making our best effort to meet the requirement, but not be penalized (found out-of-compliance) for something beyond our control. **Response:** This is the SDT's intent. The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6). > The frequency setting of first stage load shedding should be the same across the Eastern Interconnected system. **Response**: The SDT does not share this view. Existing UFLS programs in the Eastern Interconnection have various initial thresholds. As long as the performance characteristics are achieved, differences in first stage frequency trip points between regions are acceptable from a reliability standpoint. > The frequency set points mentioned in the document such as 58.0, 59.5, 61.0, etc. have been established decades ago by compiling the result of survey from different manufacturers in the IEEE publication. If a common set of frequency setpoints to be adopted for system wide usage, then, it is prudent that these settings be revisited. **Response:** These values have been selected to coordinate with the turbine capability of manufacturers reflected in PRC-024 generator off-nominal frequency performance requirements. The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.
Bandera Electric Cooperative	Yes	The TRE UFLS SDT believes the NERC standard should recognize the coordination requirements within and between the region's automatic UFLS and other frequency-related load shed programs. **Response:** The SDT disagrees that the proposed standard should recognize the coordination requirements within and between the region's automatic UFLS and other frequency related load shed programs. The Planning Coordinators will need to consider any such programs to ensure that implementation of these programs coordinate with the performance characteristics contained in the proposed continent-wide standard. The continent-wide performance criteria should require the regional standard clearly state the authority (i.e., RE, TP, TO, DSP, LSE, etc) that is responsible for the various requirements specified in the standard. **Response:** The SDT agrees and the applicability is now being identified in the proposed continent-wide standard.

Organization	Question 9	Question 9 Suggested Revisions:
		The TRE UFLS SDT also questions if the NERC performance criteria should set the values for frequency decline (etc) in the NERC characteristics? Could these be a required characteristic but set by the Region with proof of methodology? **Response:** The proposed UFLS program performance characteristics are reasonable means to set a coordinated level of performance for regional UFLS programs without restricting flexibility to specify UFLS program design parameters that best accommodate regional needs. The performance characteristics also ensure coordination with generator under-frequency trip points being developed for PRC-024 in Project 2007-09, Generator Verification. Also, what supporting documentation for restricting frequency overshoot to 61.0 Hz? We request that that NERC Generation Verification SDT state its reasoning/explanation. **Response:** Based on industry comment, the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024). The TRE UFLS SDT also expresses its concern regarding compliance issues. For example, how will compliance be addressed for an entity which meets the region's UFLS program's design standards, yet the program does not yield the results expected under actual conditions? How will compliance be determined? **Response:** The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6).
Orrville Utilities	Yes	This standard should only apply to entities that have the capability of monitoring regional load imbalance. Many distribution providers (DPs) and load serving entities (LSEs) such as municipal utilities and REAs have no knowledge of their regional load status. If these DPs and LSEs are required to own and maintain any type of automated load shedding system, it will be triggered on the basis of frequency. This could possibly cause them to shed load under localized frequency excursions caused by severe weather, which is not required by this standard as written. If load imbalance will remain an integral part of this standard, then entities that do not have the capability to track regional load should be exempt from it. **Response:** The monitoring of real-time load imbalance is neither required nor applicable. The percent generation-load imbalance specified in item 4 (now Requirement R6) is intended to be used in simulation and serve as the basis for coming up with technical design parameters consisting of frequency trip points, step sizes, time delays, etc. All regional under-frequency load shedding (UFLS) programs must be triggered on frequency. Localized frequency excursions can occur only if a local area becomes disconnected (islanded) from the interconnection. If an island does occur and frequency falls below the trip points, the proposed

Organization	Question 9	Question 9 Suggested Revisions:
		standard requires that load shall be shed in accordance with the UFLS program's technical design parameters. An additional provision of this standard should be to allow DPs and LSEs that draw less than 100 megawatts (perhaps a larger number may be appropriate) from the BES to isolate themselves from the BES before a frequency excursion reaches 59.0 Hz, and/or before the duration of the excursion has reached 30 seconds. Some DPs and LSEs generate a portion of their load, and allowing them to isolate themselves early may enable them to maintain electric service to hospitals, municipal water systems, police and fire departments in the event that the BES cannot be saved from blackout. **Response:** Uncoordinated isolation of DPs or LSEs must be avoided. The Planning Coordinators will need to ensure that isolation of DPs or LSEs coordinate with the performance characteristics contained in the proposed continent-wide standard.
Midwest ISO	Yes	Item 10.1 should not require dynamic simulation but rather analytical studies.
Response: SDT believes it is not possible to demonstrate that the adequacy of the implementation of the regional UFLS program in achieving the performance characteristics can be verified without some sort of dynamic simulation.		
Southern Company Services, Inc	Yes	Requirement 2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording needs to be changed because it requires that islands shall be identified through system studies or actual system operations. Some systems may not have experienced any islanding events and system studies may not show any potential events. The wording should be changed so that "other islands deemed appropriate" can be used as the only islands, not just as additional islands. The sentence should read "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." **Response:** The SDT agrees that the wording in the proposed standard needs to be clarified. It is important that islands used for UFLS assessments are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analysis used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5. Other areas: 1) Requirement 6 (if not replaced as proposed in our response to Question 6) - "The Standard shall specify how generators that are non-compliant with the PRC-024 underfrequency tripping requirement shall avoid jeopardizing UFLS effectiveness, or how [[insert "the entity(s)"]] [[strike "entities"]] responsible for designing UFLS shall compensate?" **Response:** The SDT has decided to revise and combine characteristics 5 and 6 (now covered by Requirement R7). In doing so,

Organization	Question 9	Question 9 Suggested Revisions:
		we have eliminated the references to PRC-024. 2) At Requirements 10.2, 10.3 and 11 and observation was made that the use of "responsible entity" and "entity(s) responsible" seems inconsistent across the three characteristics. If the terminology is consistent, perhaps the drafting team would consider placing Item 11 immediately after Item 9. Both characteristics address "owning, installing, and setting UFLS equipment". **Response:** The applicability is now being identified in the proposed continent-wide standard. 3) Requirement 11 - "The Standard shall require that the entity(s) responsible for owning, installing, and setting UFLS equipment, in accordance with item 9 above, shall annually certify [[strike "that"]] the amount of load it expects to shed during a system event which results in system frequency excursions below the initializing set points of the regional UFLS standard." **Response:** The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. The SDT has revised characteristic 9 (Requirement R10) to specify that "Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which they operate.
Florida Reliability Coordinating Council	Yes	The design of a coordinated underfrequency load shedding program is primarily a planning activity that is based on analysis of potential islanding scenarios. With the exceptions noted above, it is reasonable to expect that a UFLS program's technical design parameters will meet the electrical design requirements identified in item four of the UFLS Regional Reliability Standard Characteristics, for a load mismatch of 25%. Meeting these frequency and voltage design limits becomes increasingly difficult with higher load mismatch scenarios. The UFLS Regional Reliability Standard Characteristics as currently drafted implies the performance requirements should be applicable to both planned contingency scenarios and to actual performance during frequency excursions. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of at least 25% will meet the frequency and voltage performance requirements. Applying these requirements to actual disturbance events is inappropriate because of the large number of possible scenarios that may lead to frequency excursions. It is possible that an actual system islanding event occurs through a complex combination of multiple outages and adverse operating conditions that are impossible to predict. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of at least 25% will meet the frequency and voltage performance requirements. Accordingly, the words "or actual system operations" should be removed from item 2 in the UFLS Regional Reliability Standard Characteristics. **Response:** The comment reflects the SDT's intent. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. Compliance with performance characteristics when the imbalance is

Organization	Question 9	Question 9 Suggested Revisions:
		greater than 25 % is not required by this standard. The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6). Item 5 in the UFLS Regional Reliability Standard Characteristics as currently worded would prevent the use of additional layers of backup UFLS protection. The FRCC requires 9 UFLS steps be armed with a total of 56% of planned peak load. Some of these steps provide backup levels of protection in case unplanned generator trips occur. The words by requiring that UFLS programs complete execution before generators begin to trip on underfrequency should be removed from item 5 in the UFLS Regional Reliability Standard Characteristics. **Response:** The SDT believes that proposed performance characteristic values are achievable for generator deficits up to and including 25%. For an imbalance up to and including 25%, these performance characteristics must be met; however, for an imbalance exceeding 25%, the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The requirement for UFLS programs to complete execution before generators begin to trip has been removed. However, the Planning Coordinators would still need to show that their UFLS program design satisfies the performance characteristics in Requirement R6. The characteristics, as written, do not allow for a Regional Entity to set the design parameters of a UFLS Program. Since the FRCC has a single UFLS Program, to meet these characteristics the FRCC would be required to write a Regional Standard that would require compliance by the FRCC. The characteristics should be modified to state that these design parameters are required in a Regional Standard, if the Region has UFLS Programs designed by others. They should also state that a Regional Entity may have a UFLS Program and the program should be designed to meet these design parameters. **Response:** While the approach proposed in the first posting would have allowed the regional standard to assign the responsibility for setting the design parameters, the proposed continent-wide standard requires the Planning Coordinators within a region to define the amount of load shed required, how many blocks, at what frequency, etc.
SERC	Yes	Requirement 2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording needs to be changed because it requires that islands shall be identified through system studies or actual system operations. Some systems may not have experienced any islanding events and system studies may not show any potential events. The wording should be changed so that "other islands deemed appropriate" can be used as the only islands, not just as additional islands. The sentence should read "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS."

Organization	Question 9	Question 9 Suggested Revisions:
Response: The SDT agrees that the wording in the proposed standard needs to be clarified. It is important that islands used for UFLS assessments are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analysis used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5.		
Buckeye Power, Inc.	Yes	It is very important for Major Objective 1 from project 2007-01 to be achieved. If the standard increases costs significantly without providing a demonstrated reliability improvement it will be burdensome for some entities to bear without adding reliability value. A study should be performed to analyze the existing system requirements and to analyze where flexibility can increase or decrease value in the UFLS regional systems as part of the characteristics of the UFLS standard. The study can be used to aid in drafting the regional standard from a quantitative or technical perspective allowing for database coordination.
Response: The SDT's intent is to avoid imposing substantial costs with little or no incremental reliability benefit. The proposed continent-wide standard is intended to leverage existing practices while ensuring that these programs meet a continent wide level of reliability. Flexibility in choosing UFLS design parameters is maximized by specifying performance characteristics rather than continent-wide design parameters. There is a range of design parameters that regions may choose within that will allow UFLS programs to achieve the performance characteristics. A study by the Planning Coordinators within each region will be necessary to verify that the UFLS programs' technical design parameters achieve the performance characteristics.		
Northeast Utilities	Yes	Consider whether the document should ensure that responsible parties manage their automatic reclosing programs, along with the UFLS program.
Response: The SDT added a requirement to the proposed standard (Requirement R7.3) to include the modeling of automatic load restoration in the five year assessment.		
Progress Energy Carolinas, Inc.	Yes	Characteristic #2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording needs to be changed because it requires that islands shall be identified through system studies or actual system operations. Some systems may not have experienced any islanding events and system studies may not show any potential events. The wording should be changed so that "other islands deemed appropriate" can be used as the only islands, not just as additional islands. The sentence should read "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS."
Response: The SDT agrees that the wording in the proposed standard needs to be clarified. It is important that islands used for UFLS assessments are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analysis used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5.		
Alliant Energy	Yes	In general we believe it should be left to the Regions to determine what the UFLS limits should be.

Organization	Question 9	Question 9 Suggested Revisions:
		As noted in this questionnaire, the SDT found that there are many ways to perform the UFLS function, depending on the characteristics of the Region. We believe that NERC should insure that there is a UFLS program in place in each region, that there is adequate technical justification for each region's UFLS program, the program is reviewed annually and the necessary changes made, etc. The Regions should be responsible to perform the necessary studies, determine the UFLS setpoints, undershoot/overshoot targets, etc. and enforce them. We believe that will deliver the most flexible and efficient method to implement UFLS. **Response:** Specifying performance characteristics is a reasonable means to set a minimum level of performance for regional UFLS programs without restricting flexibility to specify UFLS program design parameters that best accommodate regional needs. They establish common performance requirements to facilitate coordination between regions in an interconnection. They also ensure coordination with generator under-frequency trip points also being developed for PRC-024 in Project 2007-09, Generator Verification. Requirement 10.1: Change "through dynamic simulations" to "through analytical studies" because verification of meeting some performance requirements can be performed with other types of methods and simulations. **Response:** SDT believes it is not possible to demonstrate that the adequacy of the implementation of the regional UFLS program in achieving the performance characteristics can be verified without some sort of dynamic simulation. There needs to be an awareness that overvoltages will affect the performance of UFLS load shedding due to the increases in system load. One approach is to trip capacitors along with load (or take comparable actions) to try to keep voltages reasonable. Switchable high voltage line shunts and reactors also need to be considered where appropriate. Obviously, the goal would be to keep voltages close to initial levels as load is shed yet we recognize that despite best efforts, we will get considerable fluctuation in voltage as load is shed. **Response:** The SDT agrees on the need for this awareness and thanks the commenter.
E.ON U.S.	Yes	The design parameter is dynamic in nature. The Distribution provider at E.ON U.S. installs and maintains the UFLS hardware. E.ON U.S. can not ascertain at this time how the standard will impact the extent and location of individual relays. E.ON U.S. believes that its current installation is adequate to meet this design standard but if NERC believes that they do not, the financial impact of meeting NERC's requirements could be significant. E.ON U.S. questions whether the expense required to meet the standard, as proposed, is justified given the small likelihood that an UF event will occur. **Response:** Specifying performance characteristics is a reasonable means to set a minimum level of performance for regional UFLS programs without restricting flexibility to specify UFLS program design parameters that best accommodate regional needs. They

Organization	Question 9	Question 9 Suggested Revisions:
		establish common performance requirements to facilitate coordination between regions in an interconnection. Existing UFLS programs that meet these performance requirements will not require modification. The SDT agrees that underfrequency events are unlikely, but such events can adversely impact the Bulk Electric System if properly coordinated UFLS programs are not in place. Additionally, the standard is unclear as to how often the process must be updated (annually or other) E.ON U.S. requests that the standard be changed to require updates only when system conditions change to an extent that the existing UFLS processes must be altered. This would protect against doing unneeded updates for standardized time periods but would not eliminate that requirement if system conditions warrant changes in the UFLS processes. Making updates only when necessary as opposed to an administratively determined time frame will reduce costs which will benefit customers **Response:** Characteristic 10 (now Requirement R7) indicates that the Planning Coordinators in each region shall conduct a UFLS assessment every five years. Modifications to the UFLS program are required only when the assessment demonstrates that the performance requirements are not met; however, equipment settings and installations must conform to the program requirements.
Manitoba Hydro	Yes	Rather than trying to set a uniform performance criteria, the SDT should develop the characteristic and requirements that must be included in the regional and/or sub regional UFLS programs and let the regions and subregions to specify the performance criteria to meet the requirements. A key component is to coordinate UFLS with the generator protection for various conditions within the region. Therefore, it should be the responsibility of the regions and/or subregions to design their UFLS for their respective areas.
Response: Specifying performance characteristics is a reasonable means to set a minimum level of performance for regional UFLS programs without restricting flexibility to specify UFLS program design parameters that best accommodate regional needs. They establish common performance requirements to facilitate coordination between regions in an interconnection. They also ensure coordination with generator under-frequency trip points also being developed for PRC-024 in Project 2007-09, Generator Verification.		
PacifiCorp	Yes	UFLS Regional Reliability Standard Characteristics should be coordinated and modified if the Generator Verification Standard Drafting Team changes design parameters associated with generating unit protection as well as the generator tripping for both over and under frequency levels.
Response: The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.		
CenterPoint Energy	Yes	This draft contains numerous references to islands, presupposing regional and/or predetermined islanding, which may not be applicable for all interconnections, especially a single region interconnection.
Response: It is important that islands used for UFLS assessments are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analysis used to identify coherent groups of generation. The SDT has clarified requirements concerning		

Organization	Question 9	Question 9 Suggested Revisions:
identification of islands in Requirements R3, R4 and R5.		
FirstEnergy Corp.	Yes	FE has the following additional comments: 1. We believe that the characteristics should include shedding of load in minimum amount of steps as appropriate for the region. For example, for some regions it is necessary to shed load in a minimum of three steps to prevent overspeed tripping. **Response:** Historically, regions have taken different approaches in establishing detailed design parameters (including amount of load shedding steps) for the region's UFLS program and the proposed standard permits these different approaches to continue provided they meet the performance characteristics. 2. With regard to characteristic #9, it would be difficult for a standard to specify the entity that owns or physically installs UFLS equipment. We suggest this be re-worded as follows: "The standard shall specify the entity(s) responsible for implementing a UFLS program." **Response:** The applicability is now being identified in the proposed continent-wide standard. 3. The minimum UFLS characteristics should require coordination between regional entities to assure a wide-area view (i.e. the entire interconnection or wide view based on engineering studies) **Response:** The SDT believes that Requirement R4 address this concern. 4. Characteristic #11 requires the regional standard include requirements for the entity to "…annually certify the amount of load it plans to shed" We question why the requirement states this since this is more of an audit function; i.e. wouldn't the compliance monitor "certify" this? This characteristic should be removed and believe that the other characteristics cover this. **Response**: The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. The SDT has revised characteristic 9 (Requirement R10) to specify that "Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which they operate." The measure by which compliance with the Requirement will be assessed will be defined in the Measures section of the proposed standard. 5. We are not clear as to the intent or purpose of Characteristic #1. We recommend that this characteristic be removed since the regional standards will require each entity to set their UFLS equipment that they own and thereby would cover the necessary system boundaries. If there is some other intent to this characteristic, we ask that the SDT explain further and then clarify the wording. **Response:** Applicability is now being identified in the proposed continent-wide standard. The SDT has also clarified requirements

Organization	Question 9	Question 9 Suggested Revisions:
		concerning identification of islands in Requirements R3, R4 and R5.
American Transmission Company	Yes	Requirement 10.1: Change "through dynamic simulations" to "through analytical studies" because verification of meeting some performance requirements can be performed with other types of methods and simulations.
Response: SDT believes it is not possible to verify that the adequacy of the implementation of the regional UFLS program meets the performance characteristics without some sort of dynamic simulation.		
Entergy	Yes	We agree with and support the SERC comments.
Response: Please see response to SERC comments.		
Southwest Power Pool	Yes	We would propose that the following statement be included in the UFLS Regional Reliability Standard Characteristics - "Each LSE in a BA footprint is to coordinate their participation in a UFLS program with the host BA." **Response:** The proposed continent wide standard includes requirements for Planning Coordinators, Transmission Owners, and Distribution Providers. The SDT does not agree that the commenter's proposal is needed in the proposed continent-wide standard.
Georgia Transmission Corporation	Yes and No	Each region is different in load to generation mix and transmission configuration. I do not believe that one rule can apply globally to all regions. Only regional stability studies can determine acceptable load shed steps and needs.
Response: Specifying performance characteristics is a reasonable means to set a minimum level of performance for regional UFLS programs without restricting flexibility to specify UFLS program design parameters that best accommodate regional needs. They establish common performance requirements to facilitate coordination between regions in an interconnection. They also ensure coordination with generator under-frequency trip points also being developed for PRC-024 in Project 2007-09, Generator Verification.		
PJM	No	
We Energies	No	
Exelon	No	
Ameren	No	

Organization	Question 9	Question 9 Suggested Revisions:
Transmission Reliability Program	No	
Independent Electricity System Operator	No	
Duke Energy	No	
City Water, Light & Power - Springfield, IL	No	
Grand River Dam Authority	No	
ERCOT	No	
American Electric Power (AEP)	No	
Louisiana Generating, LLC	No	

Consideration of Comments on the Second Draft of the PRC-006-1 - Underfrequency Load Shedding Program Requirements — Project 2007-01

The Underfrequency Load Shedding Standard Drafting Team (UFLS SDT) thanks all commenters who submitted comments on PRC-006-1 – Automatic Underfrequency Load Shedding. The standard was posted for a 30-day public comment period from April 20- May 21, 2009. Stakeholders were asked to provide feedback on the document through a special electronic standard comment form. There were 45 sets of comments, including comments from more than 120 different people from over 80 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Summary of Changes:

The applicability section of the second draft of the standard included "Distribution Providers" and "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load." This second draft language reflected the SDT's intent to establish the applicable entities in the UFLS standard to be those entities that supply UFLS capability. However, as a result of comments submitted in the second posting and further discussions within the SDT, the SDT now believes that the identification of the applicable entities was not an entirely accurate reflection of the participating registered entities. Therefore, the applicability section was modified. The SDT is now proposing that "UFLS entities" within the standard shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include Transmission Owners and/or Distribution Providers. The concept to define a group of entities within the body of the standard in the Applicability section currently exists in the CIP-002-1. In addition, the SDT included Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators in the applicability section of the standard. Transmission Owners would be subject to the standard if they have been identified by the group of Planning Coordinators as having the obligation to switch certain Elements as part of the UFLS program.

In the second posting, many of the requirements were assigned to groups of Planning Coordinators. These groups were to consist of all the Planning Coordinators within each of the Regional Entity footprints. The SDT has now revised these assignments to replace the groups with individual Planning Coordinators due to difficulties involved in assigning responsibilities to groups that do not currently exist. In the revised standard, each Regional Entity footprint must be designated as an island for UFLS program design assessment purposes. While the individual Planning Coordinator UFLS program designs maybe different, this amendment will preserve a measure of coordination at the regional level.

The SDT has revised the under and overfrequency performance characteristics to refer to under and overfrequency curves (as Attachments 1 and 2) rather than discrete points as in former drafts. The SDT believes that curves provide more uniform coordination with generator under and overfrequency tripping requirements being proposed in PRC-024-1. In addition, the team extended the underfrequency performance characteristic curve to 60 seconds from the previous 30 second duration. The team agreed to extend the underfrequency performance characteristic to permit the MRO Region to avoid having to specify a variance to cover instances where there may be slower recovery of frequency. The SDT believes that recovery of frequency within 60 seconds, though somewhat less stringent than requiring recovery within 30 seconds, remains acceptable for reliability and for coordination with generator underfrequency tripping. The SDT has similarly substituted the discrete points used in former drafts, for identifying which generator trip settings need to be included in the assessments of UFLS program design, with curves. These curves are shown on the same graphs as the performance characteristic curves (in Attachments 1 and 2) and are the same curves as are being proposed in PRC-024-1 for generator under and overfrequency tripping, thus ensuring explicit coordination between UFLS and generator tripping.

The SDT has modified the approach for ensuring coordination between regions and for selecting islands that overlap adjacent regions within an interconnection. The SDT has deleted the requirement that involved the development of procedures for coordination between groups of Planning Coordinators in neighboring regions in selecting interregional islands (version 2 of draft standard Requirement R4). In version 3 of the draft standard, any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating this selection with neighboring regions. The SDT has added a requirement for the Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by anyone Planning Coordinator that encompass more than one Planning Coordinator footprint. This revised approach to interregional coordination is contained in Requirements R5 and R13.

Some commenters noted that switching of certain transmission facilities is sometimes necessary to be carried out as part of a UFLS program design. The SDT agreed and has added Requirement R10 which requires Transmission Owners to provide automatic switching of Elements in accordance with the UFLS program design should a Planning Coordinator determine that such switching is a necessary part of the UFLS program design.

The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program."(Requirement R11). Requirement R12 requires the Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, to conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. Lastly, Requirement R13 requires the Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, to reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment completion. In the former drafts, event analysis was left to be covered by the NERC Rules of Procedure. However, the drafting team believes that including a requirement in this standard for UFLS event analysis is a more appropriate mapping of PRC-009-0 Requirement R1 which will be replaced by this standard, PRC-006-1.

Earlier in 2009, NPCC identified the need for a variance to the standard for the Québec Interconnection within NPCC. Due to the physical characteristics of the Québec system the UFLS program in Québec arrests frequency at a lower threshold and permits higher frequency overshoot than allowed in the proposed standard. The installed generation in the Québec Interconnection is 98 percent hydraulic generation, allowing wider tolerances on frequency performance without jeopardizing reliability. The variance also establishes a different capacity threshold for the generating units for which underfrequency and overfrequency trip settings must be modeled to address concerns that by 2020, 10 percent of the installed capacity in Québec may be located at plants less than 75 MVA. The Standards Committee appointed a member from the Québec Interconnection to the drafting team to develop the variance for Québec. Working closely with this representative, the team developed the variance to Requirement R3 Parts 3.1 and 3.2 and Requirement R4 Parts 4.1 through 4.6. The variance to these requirements reference separate under frequency and overfrequency curves included as attachments 1A and 2A to the standard.

In reviewing the responses to comments on the second posting, several commenters noted that certain requirements in the exiting EOP-003-1 standard conflict or are redundant with the requirements being proposed by this SDT. The team agreed with these commenters and felt that if left unaddressed, the redundancies and conflicts could result in compliance issues in the future. As a result, the team submitted a request to supplement the existing SAR for Project 2007-01 to include a revision to EOP-003-1 in order to exclude those requirements related to automatic underfrequency load shedding since PRC-006-1 will contain these. The Standards Committee approved this action and the team moved forward with revising the existing EOP-003-1 requirements. The team is presenting these modifications to the EOP-003-1

requirements in this third posting of the standard and would like industry feedback on the revisions noting that the changes were conducted with the limited purpose of removing automatic underfrequency load shedding from the scope of EOP-003. Two other drafting teams are already in place to review the other aspects of EOP-003 as part of Project 2009-02 – Real-time Tools and Project 2009-03 – Emergency Operations.

The team debated whether or not, in Requirement R4, Parts 4.1 through 4.6, to include under and over frequency trip settings only for generators connected to the BES above the stated size thresholds, or all generators above the stated size thresholds whether BES connected or not, though practically limited to 60 kV and above connections. The question here is not applicable to Generator Owners, but simply whether generator under frequency trip settings above the (proposed) under frequency curve in PRC-024-1, and generators with over frequency trip settings below the (proposed) PRC-024-1 over frequency curve, should be represented in the UFLS design assessments.

Limiting Requirement R4, Parts 4.1 through 4.6, to BES connected generation would be consistent with the NERC Statement of Compliance Registry Criteria. It was also noted that some generators on lower voltage systems above the size thresholds may not be modeled, or that they are sometimes lumped with load in planning base cases such that there could be inconsistent enforcement of this requirement if it were extended to include generators not connected to the BES. On the other hand, a distinction between BES and non-BES tripped generation is immaterial to system frequency; the amount of generation that could potentially be tripped during a frequency event is the only relevant factor. Limiting Requirement R4 to BES connected generation would also be inconsistent with PRC-024-1 Applicability Section 4.2 in its current draft (draft #2 not yet posted for comment) which includes generation down to 60 kV.

The SDT limited Requirement R4 to generators connected to the BES only. Note that this same issue also applies to Requirement R3, Part 3.3, in the monitoring of V/Hz at generators.

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Brian Bartos	TRE UFLS Standard Drafting Team	X	X			X		X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randy Jones	Calpine	ERCOT	5
2.	Raborn Reader	EPCO	ERCOT	NA
3.	Eddy Reece	Rayburn Country Electric Coop.	ERCOT	NA
4.	Barry Kremling	Guadalupe Valley Electric Coop.	ERCOT	NA
5.	Sergio Garza	Lower Colorado River Authority	ERCOT	5
6.	Steve Myers	ERCOT ISO	ERCOT	2
7.	Ken McIntyre	ERCOT ISO	ERCOT	2
8.	Dennis Kunkel	AEP	ERCOT	1
9.	Matt Pawlowski	NextEra	ERCOT	5

2.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	David O'Connor	Potomac Electric Power Co	RFC	1
2.	Dave Thorne	Potomac Electric Power Co	RFC	1
3.	Vic Davis	Delmarva Power & Light	RFC	1

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
4. John Keller		Atlantic City Electric	RFC						1			
5. Walt Blackwell		Potomac Electric Power Co	RFC						1			
6. Alvin Depew		Potomac Electric Power Co	RFC						1			
3. Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Kelly Johnson	Transmission Customer Service Engineering	WECC	1
2. Greg Vasallo	Transmission Customer Service Engineering	WECC	1
3. Larry Furumasu	Transmission Planning	WECC	1

4. Group	Guy Zito	Northeast Power Coordinating Council										X

Additional Member	Additional Organization	Region	Segment Selection
1. Ralph Rufrano	New York Power Authority	NPCC	5
2. Alan Adamson	New York State Reliability Council	NPCC	10
3. Greg Campoli	New York Independent System Operator	NPCC	2
4. Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5. Kurtis Chong	Independent Electricity System Operator	NPCC	2
6. Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7. Manuel Couto	National Grid	NPCC	1
8. Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9. Brian Evans-Mongeon	Utility Services	NPCC	8
10. Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11. Michael Gildea	Constellation Energy	NPCC	6
12. Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
13. Kathleen Goodman	ISO - New England	NPCC	2
14. David Kiguel	Hydro One Networks Inc.	NPCC	1
15. Michael Lombardi	Northeast Utilities	NPCC	1
16. Randy MacDonald	New Brunswick System Operator	NPCC	2
17. Bruce Metruck	New York PowerAuthority	NPCC	6

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
18. Robert Pellegrini		The United Illuminating Company	NPCC						1			
19. Michael Schiavone		National Grid	NPCC						1			
20. Michael Sonnelitter		FPL Energy/NextEra Energy	NPCC						5			
21. Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC						3			
22. Lee Pedowicz		Northeast Power Coordinating Council	NPCC						10			
23. Gerry Dunbar		Northeast Power Coordinating Council	NPCC						10			
5. Group	Jim Busbin	Southern Company	X		X		X					
Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1. J. T. Wood		Southern Company Services, Inc.	SERC						1			
2. Hugh Francis		Southern Company Services, Inc.	SERC						1			
3. Bill Shultz		Southern Company Services, Inc.	SERC						5			
4. Phil Winston		Georgia Power Company	SERC						3			
5. Jonathan Glidewell		Southern Company Services, Inc.	SERC						1			
6. Marc Butts		Southern Company Services, Inc.	SERC						1			
6. Group	Ken McIntyre	ERCOT ISO		X								
Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1. Steve Myers		ERCOT ISO	ERCOT						2			
2. John Schmall		ERCOT ISO	ERCOT									
7. Group	Jalal Babik	Electric Market Policy	X		X		X	X				
Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1. Louis Slade			SERC						6			
2. Mike Garton			NPCC						5			
8. Group	Jason L. Marshall	Midwest ISO Stakeholders Standards Collaborators		X								
Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1. Lee Kittleson		Otter Tail Power	MRO						1			
2. Michael Ayotte		ITC Holdings	RFC						1			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Bob Jones	SERC UFLS Standards Drafting Team	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Foster	Ameren Services Co.	SERC	1
2.	John O'Connor	Progress Energy Carolinas	SERC	1
3.	Pat Huntley	SERC Reliability Corp.	SERC	10
4.	Jonathan Glidewell	Southern Co. Services	SERC	1
5.	Tom Cain	TVA	SERC	1

10.	Group	Peter A. Heidrich	FRCC Standards & Operations Departments										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Linda Campbell	Florida Reliability Coordinating Council	FRCC	10
2.	Eric Senkowicz	Florida Reliability Coordinating Council	FRCC	10

11.	Group	Frank Gaffney	Florida Municipal Power Agency and Select Members	X		X	X	X				X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rich Kinas	Orlando Utilities Commission	FRCC	1, 3, 5
2.	Jim Howard	Lakeland Electric	FRCC	1, 3, 5
3.	Greg Woessner	Kissimmee Utilities Authority	FRCC	1, 3, 5
4.	Cairo Venegas	Fort Pierce Utilities	FRCC	1, 3, 5

12.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carol Gerou	MRO	MRO	10
2.	Neal Balu	WPS	MRO	3, 4, 5, 6
3.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
4.	Ken Goldsmith	ALTW	MRO	4
5.	Jim Haigh	WAPA	MRO	1, 6
6.	Terry Harbour	MEC	MRO	1, 3, 5, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Joseph Knight		GRE	MRO						1, 3, 5, 6			
8.	Scott Nickels		RPU	MRO						3, 4, 5, 6			
9.	Dave Rudolph		BEPC	MRO						3, 4, 5, 6			
10.	Eric Ruskamp		LES	MRO						1, 3, 5, 6			
11.	Terry Bilke		MISO	MRO						2			
13.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				
	Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1.	Tim Hinken		Kansas City Power & Light	SPP						1, 3, 5, 6			
2.	Nick McCarty		Kansas City Power & Light	SPP						1, 3, 5, 6			
3.	Jerry Hatfield		Kansas City Power & Light	SPP						1, 3, 5, 6			
14.	Group	Ben Li	IRC Standards Review Committee		X								
	Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1.	James Castle		NYISO							2			
2.	Anita Lee		AESO							2			
3.	Charles Yeung		SPP							2			
4.	Bill Phillips		MISO							2			
5.	Matt Goldberg		ISO-NE							2			
6.	Steve Myers		ERCOT							2			
7.	Patrick Brown		PJM							2			
15.	Individual	Russell A. Noble	Cowlitz County PUD			X							
16.	Individual	Edward C. Stein	Edward C. Stein - Self								X		
17.	Individual	Harvie Beavers	Colmac Clarion					X					
18.	Individual	Elvin Epting	City of Bedford			X							
19.	Individual	Ray Phillips	Alabama Municipal Electric Authority				X						

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Karl Bryan	US Army Corps of Engineers					X					
21.	Individual	Tom Nappi	NIPSCO	X		X		X					
22.	Individual	Kenneth D. Brown b/h Joseph Lalier, Design Engineer Electric Delivery Planning	Public Service Electric and Gas Company	X		X							
23.	Individual	Steve Alexanderson	Central Lincoln			X							
24.	Individual	Shawn Jacobs	SPP System Protection and Control Working Group	X	X	X							X
25.	Individual	Jonathan Appelbaum	Long island power Authority	X									
26.	Individual	Eric Mortenson	Exelon	X		X		X					
27.	Individual	Rao Somayajula	ReliabilityFirst Corporation										X
28.	Individual	Ronnie Frizzell	Arkansas Electric Cooperative Corporation				X						
29.	Individual	Greg Davis	System Protection & Control	X		X							
30.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
31.	Individual	Anthony Jablonski	Reliability First										X
32.	Individual	Bob Thomas, Kevin Wagner, Troy Fodor, Scott Robison	Illinois Municipal Electric Agency				X						
33.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
34.	Individual	Jim Sorrels	AEP	X		X		X	X				
35.	Individual	Vladimir Stanisic	Ontario Power Generation					X	X				
36.	Individual	Joe Springhetti	We Energies			X	X	X					
37.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
38.	Individual	Mike Sonnelitter	NextEra Energy Resources, LLC					X					
39.	Individual	Jason Shaver	American Transmission Company	X									
40.	Individual	Rick Terrill	Luminant Power					X					
41.	Individual	Kirit Shah	Ameren	X		X		X	X				
42.	Individual	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
43.	Individual	Armin Klusman	CenterPoint Energy	X									
44.	Individual	Dan Rochester	Independent Electricity System Operator		X								
45.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				

1. **The UFLS programs typically have been developed within each Region by representatives from the vertically integrated utilities, Control Areas, power pools, etc. in that Region. The SDT initially proposed that all UFLS requirements be contained within regional UFLS standards to utilize specific expertise within the regions and recognize that UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics, even across interconnected regions. However, based on the rationale contained in the background, the SDT has developed a continent wide standard consistent with the historical practice that promotes the utilization of previous experience and expertise. As proposed, the continent-wide standard requires that all Planning Coordinators within a Region work together as a group to develop the UFLS program for that Region that conforms to the performance characteristics.**

    a. Do you agree that creating a continent wide standard preserves the intent of utilizing specific expertise within the regions to develop UFLS programs that meet common performance characteristics?

Summary Consideration:

- Most commenters agreed that creating a continent wide standard preserves the intent of utilizing specific expertise within the regions to develop UFLS programs that meet common performance characteristics.
- Commenters suggested that regions might want to develop more detailed or stringent requirements. If a Region wants to develop more stringent requirements the Region may elect to develop a regional standard. The creation of a continent wide standard does not prohibit the creation of regional standards. Several commenters also indicated the need for a Variance. The SDT is proposing a Variance for Hydro-Quebec in the third posting of the standard. Other requests for variances or regional standards should follow the procedure outlined in the NERC Rules of Procedure Appendix 3A – Variances to NERC Reliability Standards and Section 312 - Regional Reliability Standards.
- Some comments indicated concern with the term “consistent” in Requirement R2 of the standard. The SDT developed the performance characteristics so that a “program” could be tailored to the needs of each region; however; at the same time not interfering with adjacent regions. The SDT did not intend that a “program” could have only one set of requirements, such as one set of drop frequencies or one specific percent load drop, for an entire region. A “program” could be made up of different sections or sub regional systems identified as islands with different or the same requirements where consistent application of the applicable program requirements are applied in each island. The SDT merged Requirement R2 into Requirement R6 (now Requirement R3 in the in the third version of the standard) and removed the term “consistent” in the requirement.

Organization	Yes or No	Question 1a Comments:
IRC Standards Review Comittee	No	By definition, a continent wide standard intends to direct all regions into a consistent requirement and requires regions with varying practices to agree to a single standard. We support the approach taken in PRC-006-01 that specifies only the upper and lower bounds of UFLS protection requirements. We believe this is a reasonable approach to establish continent-wide requirements and allow regional expertise to design their regional UFLS programs.We agree with the proposal to preserve the intent of utilizing specific expertise within the regions to develop UFLS programs, but do not agree with the applicability and the way the standard is written to hold the Group of Planning Coordinators responsible for the requirements. Please see our comments under Q1b
Response: Thank you for your support to the continent-wide approach. See the response provided for the comment under Q1b.		
Ameren	No	It seems that regional standards with continent-wide performance characteristics would be the best mechanism to achieve this purpose. The only reason to have a continent wide standard to is to subscribe to the NERC process. There seems to be more focus on the process than the ultimate goal.
Response: The SDT has focused on both the ultimate goal and the process to achieve the goal. We believe the ultimate goal is to have regionally developed UFLS programs that are coordinated across and between regions. As drafted, the proposed standard does not preclude the development of regional standards. The standard directs responsibility to the Planning Coordinators but allows them to develop/establish the UFLS program requirements in any manner they deem appropriate as long as they conform to the performance characteristics.		
Independent Electricity System Operator	No	Further, we propose the scope of the standard be revised to clearly indicate that it focuses on the global events, as follows:To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following widespread underfrequency events.
Response: The SDT does not agree with the inclusion of word "widespread" because of the numerous difficulties in defining "widespread" and the lack of completeness of the intent. The draft standard requires consideration of appropriate potential islands. Such islands may be widespread in some people's minds and not so in others. Widespread, if viewed from a square mile perspective, could include large rural areas with little "critical" load. "Critical" urban load in relatively small concentrated geographic footprints may not necessarily fit within a widespread definition. The drafted purpose allows all these conditions to be included as appropriate with the programs to cover the relevant impacts to the bulk electric system.		
NIPSCO	No	It really depends on how this is accomplished.
Response: The SDT encourages the commenter to provide more specifics in the next posting for SDT consideration.		

Organization	Yes or No	Question 1a Comments:
Duke Energy	No	R2 requires consistent application across the region. As long as R6 is met, there should be no requirement for all systems within the region to be consistent. This will create unnecessary work to redesign systems that could meet R6 just because they are not consistent with other systems in the region. Recommend deleting the words consistent application across from R2. This is similar to not requiring the regions to be consistent as long as R6 is met.
Response: The SDT merged Requirement R2 into Requirement R6 (now Requirement R3 in the in the third version of the standard) and removed the term "consistent" in the requirement.		
We Energies	No	We agree that a continent wide standard should be developed. However, we disagree with the approach taken with this draft of the standard. See our question 8 comments for more detail.
Response: Thank you for the support of a continent-wide standard. See the response to your comments on Question 8.		
TRE UFLS Standard Drafting Team	Yes	The Texas Regional Entity Underfrequency Load Shedding Standard Drafting Team (TRE UFLS SDT) is pleased to provide these comments. These comments reflect the consensus of this specific regional standard drafting team and do not reflect the position of the Texas Regional Entity or ERCOT. The TRE UFLS SDT agrees that the basic common characteristics associated with the proposed UFLS standard provides for an appropriate level of required coordination within and, where applicable, between regions.
Response: Thank you for your comment.		
Pepco Holdings, Inc - Affiliates	Yes	The PHI Affiliates agree that the Planning Coordinators have their own expertise and access to the expertise of the TOs and DPs in their area.
Response: Thank you for your support to the continent-wide approach.		
Bonneville Power Administration	Yes	The continent-wide standard is a MINIMUM. Regions may still apply a higher standard.
Response: If a Region wants to develop more stringent requirements the Region may elect to develop a regional standard. The creation of a continent wide standard does not prohibit the creation of regional standards. Requests for variances or regional standards should follow the procedure outlined in the NERC Rules of Procedure Appendix 3A – Variances to NERC Reliability Standards and Section 312 - Regional Reliability Standards.		
SERC UFLS Standards	Yes	We agree that creating a continent wide standard will preserve the intent of utilizing specific expertise within the

Organization	Yes or No	Question 1a Comments:
Drafting Team		region to develop UFLS schemes. First of all, this approach will provide uniformity among the regions for developing UFLS schemes, as all the regions will follow a consistent performance characteristics specified in the standard. At the same time, the regions will have the flexibility to develop their own requirements to meet their specific needs.
Response: Thank you for your comment.		
Southern Company	Yes	Southern Company agrees with the comments submitted by the SERC Region for all questions in this comment form. Submitted SERC responses are essentially replicated in the responses we submit for Southern Company for questions 1-8.**********We agree that creating a continent wide standard will preserve the intent of utilizing specific expertise within the region to develop UFLS schemes. First of all, this approach will provide uniformity among the regions for developing UFLS schemes, as all the regions will follow consistent performance characteristics specified in the standard. At the same time, the regions will have the flexibility to develop their own requirements to meet their specific needs.
Response: Thank you for your comment.		
FRCC Standards & Operations Departments	Yes	We agree with the concept of the development of a Regional UFLS program that conforms to the common performance characteristics contained in the draft standard; however it is not clear what constitutes a 'region'. The SDT has repeatedly used the capitalized version ('Region') of the word in all of the associated documents (i.e. background, comment form) and reverted back to lower case version (region) in the standard. We believe that 'region' should be defined in the standard and incorporated into the NERC Glossary of Terms. This will ensure that the appropriate scope is applied in the development of Regional UFLS programs.
Response: The SDT intended "region" to relate to the traditional sense of a RRO with defined boundaries and that is in the NERC Glossary, although somewhat out of date. The SDT did inadvertently capitalize the word "region" in the associated documents but did use it appropriately in the standard. The SDT has replaced "region" with "Regional Entity footprint."		
US Army Corps of Engineers	Yes	The continent wide standard establishes the performance characteristics that must be met and requiring the PCs within a Region to develop the specifics allows the implementation of the Rel Stndrd to also include local variances and has the added benefit of maintaining planning expertise.
Response: Thank you for your support to the continent-wide approach.		
Public Service Electric and Gas Company	Yes	The creation of a continent wide standard is acceptable as long as the responsibility for developing a UFLS program remains with the Planning Coordinators/Authorities in the Regions.

Organization	Yes or No	Question 1a Comments:
Response: Thank you for your support to the continent-wide approach.		
System Protection & Control	Yes	A continent wide standard will create desired system performance criteria, while allowing flexibility within the regions.
Response: Thank you for your support to the continent-wide approach.		
AEP	Yes	As each Reliability Coordinator has it's own UFLS requirements, the UFLS programs between the Reliability Coordinator's need to work together.
Response: Thank you for your comment. Reliability Coordinators are not included in this standard because this standard addresses only multi-step automatic relay tripping and load shedding, not manual load shedding. The draft standard includes requirements to ensure coordination within a region by designating each Regional Entity footprint as a required island for which the performance characteristics must be satisfied, and by requiring Planning Coordinator concurrence on UFLS design assessment results on those islands.		
PacifiCorp	Yes	PacifiCorp believes that the standard language is general enough to allow for regional differences. It is appropriate that the standard addresses what the parameters are, not how the parameters are to be implemented.
Response: Thank you for your support to the continent-wide approach.		
Northeast Power Coordinating Council	Yes	
ERCOT ISO	Yes	
Electric Market Policy	Yes	
Midwest ISO Stakeholders Standards Collaborators	Yes	
Florida Municipal Power Agency and Select Members	Yes	

Organization	Yes or No	Question 1a Comments:
MRO NERC Standards Review Subcommittee	Yes	
Kansas City Power & Light	Yes	
Cowlitz County PUD	Yes	
Edward C. Stein	Yes	
Colmac Clarion	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
Central Lincoln	Yes	
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
Exelon	Yes	
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	Yes	

Organization	Yes or No	Question 1a Comments:
ReliabilityFirst	Yes	
Illinois Municipal Electric Agency	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Ontario Power Generation	Yes	
NextEra Energy Resources, LLC	Yes	
American Transmission Company	Yes	
Luminant Power	Yes	
FirstEnergy Corp	Yes	
Xcel Energy	Yes	

b. Do you agree that the SDT has assigned responsibility to the appropriate entity?

Summary Consideration:

1. Some commenters expressed concern over the "group" concept for Planning Coordinators and how it would be implemented. The SDT has removed the group concept from the standard. The applicability has been changed to individual Planning Coordinators. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning Coordinators join a group that does not presently exist.
2. While some commenters agreed with the concept of the coordinated effort to design an underfrequency load shedding program, they expressed a need to establish an entity with the overall responsibility of coordinating the efforts of the Planning Coordinators. These commenters recommended that the Regional Entity be responsible for overseeing the development of the Regional UFLS program while requiring the Planning Coordinators to participate in the process. The SDT notes that Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard.
3. Some commenters thought that Generator Owner should be included as an applicable entity. This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.
4. Some commenters thought that the Transmission Planner is the more appropriate applicable entity. The SDT believes the Planning Coordinator is the most appropriate applicable entity because design of a UFLS program should consider the widest possible geographic area. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role, the SDT anticipates that the Transmission Planners' expertise will be utilized.
5. Some commenters indicated that Reliability Coordinators should be included in the standard. Reliability Coordinators are not included in this standard because this standard addresses only multi-step automatic relay tripping and load shedding that must be planned and implemented in advance. The SDT believes that Planning Coordinators are the appropriate entities for this function. Manual load shedding is not covered by this standard.
6. Some commenters stated that the Transmission Owner should be removed as an applicable entity because any Transmission Owner with load must be registered as a Distribution Provider. In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. (Also covered under Question 1b.)

Organization	Yes or No	Question 1b Comments:
Northeast Power Coordinating Council	No	We agree that the Planning Coordinator is the correct Functional Model entity based on having a wide-area view and the planning expertise to perform UFLS assessments. However, it is not clear to us whether applicability can be assigned to a group of Planning Coordinators as opposed to individual Planning Coordinators.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
Midwest ISO Stakeholders Standards Collaborators	No	We can understand the assignment of certain responsibilities to a Planning Coordinator. However, attempting to force Planning Coordinators to develop groups and then holding the entire group accountable for one another's compliance is unworkable.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
SERC UFLS Standards Drafting Team	No	No, because Planning Coordinator(PC) role is implemented differently across the regions. The Transmission Planner(TP) is the most appropriate entity to design the UFLS scheme since the TP has the detailed system knowledge and is generally better positioned to develop the scheme. Also, the Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.
Response: The SDT believes the Planning Coordinator is the appropriate applicable entity because design of a UFLS program should consider the widest possible geographic area. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role, the SDT believes that the Transmission Planners' expertise will be utilized. **The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.**		
Southern Company	No	No, because the Planning Coordinator (PC) role is implemented differently across the regions. The Transmission Planner (TP) is the most appropriate entity to design the UFLS scheme since the TP has the detailed system knowledge and is generally better positioned to develop the scheme. Also, the Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the

Organization	Yes or No	Question 1b Comments:
		Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.
Response: The SDT believes the Planning Coordinator is the appropriate applicable entity because design of a UFLS program should consider the widest possible geographic area. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role the SDT anticipates that the Transmission Planners' expertise will be utilized. **The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.**		
FRCC Standards & Operations Departments	No	Although we agree with the concept of the coordinated effort to design an underfrequency load shedding program, we believe that there is a need to establish an entity with the overall responsibility of coordinating the efforts of the Planning Coordinators. We recommend that the Regional Entity be responsible for overseeing the development of the Regional UFLS program while requiring the Planning Coordinators to participate in the process. Although the provided background material dismisses the idea of expanding the applicability to include the Regional Entity, the precedent has been established by assigning applicability to the Regional Entity in the CIP standards.
Response: Unfortunately, though the SDT agrees with the commenter's point on assigning applicability to Regional Entities, Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard.		
Florida Municipal Power Agency and Select Members	No	While we agree that the responsibility resides with a regional planning coordinator type of Entity, a group of Planning Coordinators is a somewhat nebulous term and calls into question the enforceability of the standard, and therefore calls into question whether FERC will approve it or not. If the group of Planning Coordinators is noncompliant, who is noncompliant? Who negotiates settlement? Who would pay a potential fine? If one of the Entities does not provide data for the database required in R8, are all of the PCs noncompliant? As with nearly all things, in order to get something done, leadership is necessary, so, although this is certainly a team effort, one Entity ought to be designated to offer that leadership. Why not keep it the Regional Entity? Alternatively, is there sufficient justification to create a new function called the Regional Planning Coordinator? Or to change the definitions of Planning Coordinator, Transmission Planner and Resource Planner to essentially cause Transmission Planners and Resource Planners to focus on more local issues whereas the Planning Coordinator by definition becomes regional (and hence eliminates the need for the term a group of Planning Coordinators?)
Response: Thank you for your comment. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning Coordinators join a group that does not presently exist. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators. Unfortunately, though the SDT agrees with the commenter's point on assigning		

Organization	Yes or No	Question 1b Comments:
applicability to Regional Entities, Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard.		
MRO NERC Standards Review Subcommittee	No	We agree with the assignment of selected responsibilities to the Planning Coordinator (PC) and suggest that the NERC Compliance Registry Criteria be revised to add the Planning Coordinator function and the Regional Entities be directed to register applicable entities to this function. Responsibility for several requirements are assigned to a "group" of Planning Coordinators. However, these groups do not presently exist and are not registered or legal entities. Perhaps a Planning Coordinator Group (PCG) should be added to the Applicability section and the NERC Compliance Registry Criteria be revised to add the PCG function, similar to the Reserve Sharing Group (RSG) function. Then, Regional Entities might be directed to register applicable entities to this function. Establishing PCGs would help PCs clarify how the group's responsibilities for compliance and liabilities would be assigned to each of its members.If a registered PCG function is not established, then drafting team should revise R1 to require all Planning Coordinators in a region to form a joint agreement to cover fulfillment of the subsequent UFLS requirements. See details in response to question 8. Transmission Owners function should be removed because it is unnecessary and redundant with the Distribution Provider function. Per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner that provides and operates the ?wires? to end-use Load served at transmission voltages must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. However, the TO function should be retained if SDT adopts the suggestion of adding R11 and R12 reguarding reactive power devices (in Q8). Generator Owners should be assigned responsibility for coordinating any generator off nominal frequency protection with any applicable UFLS relaying and for providing generator off nominal frequency protection information to the Planning Coordinator. So, the Generator Owner function should be added to the Applicability section. The SDT should coordinate with PRC-024 so that requirements do not overlap.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning Coordinators join a group that does not presently exist. **In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.** **Regarding the comment on reactive power devices referred to in Question 8 the team directs the commenter to the SDT response under Question 8.** **This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-**		

Organization	Yes or No	Question 1b Comments:
024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.		
Kansas City Power & Light	No	It is unnecessary to designate a Transmission Provider with end-use load. That is a Distribution Provider. Generator Owners should be added since generator data will be required to be provided for modeling purposes.
Response: The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. **This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.**		
IRC Standards Review Comittee	No	We do not agree with the SDT to remove the Regional Entities from being assigned requirements on the basis that: ?? the Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements.? There are a number of existing standards, for examples: CIP standards, BAL-002, EOP-004, EOP-007, FAC-013, FAC-012, to name a few, that hold the Regional Entities (Regional Reliability Organizations, as written) responsible for standard requirements. Unless and until an assessment is conducted to conclude that all such requirements can be replaced with an alternative responsible entity(ies), we do not see a problem with the Regional Entities being held responsible for complying with standards.The way the requirements are assigned in this draft standard (each group of Planning Coordinators shall) leaves room for confusion to the industry and debates in the compliance audit process. Unless the Group of PCs is registered as an entity, we are unable to see how the pertinent requirements can be legally enforced. An alternative is to assign these requirements to the Regional Entities, OR, develop a requirement for each PC to have an agreement with its Regional Entity to engage in the design of a UFLS program and coordinate settings with other PCs? programs to achieve consistent application across the region. This way, the requirements can be written to hold Each Planning Coordinator rather than Each group of Planning Coordinators. If this approach is adopted, R1 and R2 could be combined as follows:R1. Each Planning Coordinator shall have an agreement with its Regional Entity to participate with other Planning Coordinators within the region in coordinating the design of an underfrequency load shedding program for consistent application across the region.With this change, R3 may be combined with R1 or be a separate requirement holding each PC responsible for engaging in the development of the criteria.And R3 to R8 can be revised to ?Each Planning Coordinator, in meeting the intent of R1, shall?The proposed changes provide clarity to the PC?s responsibility and removes gray areas in the compliance audit process.
Response: The SDT notes that Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning		

Organization	Yes or No	Question 1b Comments:
Coordinators join a group that does not presently exist. Accordingly, the SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
Independent Electricity System Operator	No	We do not agree with the SDT to remove the Regional Entities from being assigned requirements on the basis that: ?? the Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements. There are a number of existing standards, for examples: CIP standards, BAL-002, EOP-004, EOP-007, FAC-013, FAC-012, to name a few, that hold the Regional Entities (Regional Reliability Organizations, as written) responsible for standard requirements. Unless and until an assessment is conducted to conclude that all such requirements can be replaced with an alternative responsible entity(ies), we do not see a problem with the Regional Entities being held responsible for complying with standards.The way the requirements are assigned in this draft standard (each group of Planning Coordinators shall) leaves room for confusion to the industry and debates in the compliance audit process. Unless the Group of PCs is registered as an entity, we are unable to see how the pertinent requirements can be legally enforced. An alternative is to assign these requirements to the Regional Entities, OR, develop a requirement for each PC to have an agreement with its Regional Entity to engage in the design of a UFLS program and coordinate settings with other PCs programs to achieve consistent application across the region. This way, the requirements can be written to hold Each Planning Coordinator rather than Each group of Planning Coordinators. If this approach is adopted, R1 and R2 could be combined as follows:R1. Each Planning Coordinator shall have an agreement with its Regional Entity to participate with other Planning Coordinators within the region in coordinating the design of an underfrequency load shedding program for consistent application across the region.With this change, R3 may be combined with R1 or be a separate requirement holding each PC responsible for engaging in the development of the criteria.And R3 to R8 can be revised to ?Each Planning Coordinator, in meeting the intent of R1, shall??The proposed changes provide clarity to the PC?s responsibility and removes gray areas in the compliance audit process.
Response: The SDT notes that Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning Coordinators join a group that does not presently exist. Accordingly, the SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
Central Lincoln	No	"Transmission Owners with end-use Load connected to their Facilities where suchend use load is not part of a Distribution Providers load"TOs that meet the registry criteria for DP should be registered as such. If they don't meet the criteria, they are not required to have UFLS and this standard is not applicable to the small unregistered distribution system in question. Instead, I propose that TOs be included with no qualification, or a qualification that expresses the following situation: A DP and a TO may jointly decide the most effective location for UFLS may be on the TO's system, where it may be

Organization	Yes or No	Question 1b Comments:
		easier to reach the load shedding target. It would then be the TO that would be required to meet R9 and R10.
Response: The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Exelon	No	GOs should be included as applicable entities because they play an important role in matching load and generation in periods of frequency excursion. That being said, the standard should not require the installation of under frequency relays at generators that would remain on line beyond these minimum requirements.
Response: This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.		
Arkansas Electric Cooperative Corporation	No	I agree with the Planning Coordinator Group concept but this group should be required to solicit the input from other functional entities such as the GO, TO, TOP, DP, and LSE when developing the criteria and plans. These other entities will have valuable insight as to what should and should not be included in the UFlS programs and need to have a voice during the development of these programs. I would suggest adding the following sentence to R2 and R3 "The design(R2)/criteria(R3)shall be developed taking into consideration the input and feedback from the Generator Owners, Transmission Owners, Transmission Operators, Distribution Providers and Load Serving Entities to which the design/critria shall apply." While the Distribution Provider may own the equipment the LSE will play a valuable role in determining which equipment should be used to shed load. The LSE and not necessarily the DP has a better knowledge of the load makeup served by the DP's equipment and thus may be in a better position to identify the best location for UF relays. For example the LSE would know if a circuit has a critical load where the DP may or may not have this knowledge. Since load is what is being dropped, the LSE is the best one to make the determation of which load is to be shed. The LSE may not need be an applicable entity but the UF programs and plans should not be developed without their input.It may be that the standard applicability needs to be expanded to these other entities by adding something to the effect of: GO, TO, TOP, DP, and LSE will participate in the development of the UFLS program and plans by providing input and feedback.
Response: The commenter is referencing issues that must be addressed to determine "how" the program is to be developed and implemented. The standard states measurable requirements for "what" is to be accomplished. Choice of load to be tripped, for example, is an implementation issue not specified in the standard. Responsible entities are allowed to choose the most appropriate manner in which to implement the program design to achieve the reliability objective of arresting frequency decline. The continent-wide standard also does not preclude the use of the regional standard development process that may involve these other entities to produce a regional standard. Note that the SDT has removed the group of Planning		

Organization	Yes or No	Question 1b Comments:
Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
Duke Energy	No	The proposed standard's requirements R1-R8 are applicable to Planning Coordinator, which isn't a registered function in NERC's compliance registry. Without applicability to a registered entity such as the Planning Authority or Transmission Planner, there is no clear responsibility for compliance. Also it is unclear how compliance can reasonably be enforced when responsibility is shared by a group of entities. It is not clear how non-compliance with R6 is addressed given that all PCs in the region are combined by R1. Somehow, each PC must be allowed to demonstrate compliance to the standard independently so compliant PCs are not penalized along with the non-compliant one(s).
Response: NERC has submitted and FERC has accepted a statement that the previously defined term of Planning Authority is the same entity/function as the currently approved Functional Model term Planning Coordinator. Based on the "Comments of the North American Electric Reliability Corporation on the Notice of Proposed Rulemaking for Facilities Design, Connections and Maintenance Reliability Standards", Docket No. RM07-3-000, dated September 19th, 2007, pages 15 and 16, NERC states: "While NERC recognizes there will be a need to modify the compliance registration process to include the planning coordinator, in the future, on an interim basis, any requirement assigned to the planning authority is assumed also to apply to the planning coordinator. Because no approved standards apply to the "planning coordinator at this time, the modification to the NERC Compliance Registry is not a current issue." This document can be found at: http://www.nerc.com/docs/docs/ferc/FinalFAC.pdf. Based on this document, the SDT feels the Planning Coordinator is the correct entity. **In addition, the current NERC Glossary of terms indicates that the Planning Authority and Planning Coordinators are the same.** **The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.**		
ReliabilityFirst	No	The Transmision Owner with end use load connected ... is out of line with the NERC Functional Model knowing that if a Transmision Owner has end use load connected, by definition, the Transmision Owner must register as a Distribution Provider. Therefore, using just the Distribution Provider in the UFLS standard is adequate and complete.
Response: In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Hydro-Québec TransEnergie (HQT)	No	HQT agree that the Planning Coordinator is the correct Functional Model entity based on having a wide-area view and the planning expertise to perform UFLS assessments. However, it is not clear whether applicability can be assigned to a group of Planning Coordinators as opposed to individual Planning Coordinator.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability		

Organization	Yes or No	Question 1b Comments:
has been changed to individual Planning Coordinators.		
AEP	No	Reliability Coordinators have set up specifics standards on the set points for UFLS. The proposed standard misses this circumstance by not including the Reliability Coordinator in the standard. How would this be reconciled?
Response: Reliability Coordinators are not included in this standard because this standard addresses only multi-step automatic relay tripping and load shedding that must be planned and implemented in advance. The SDT believes that Planning Coordinators are the appropriate entities for this function. Manual load shedding is not covered by this standard.		
We Energies	No	See our question 8 comments for more detail.
Response: See response to Question 8 comments.		
American Transmission Company	No	We agree with the assignment of selected responsibilities to the Planning Coordinator (PC) and suggest that NERC revise the Compliance Registry Criteria to add the Planning Coordinator and direct the Regional Entities to register applicable entities to this function. Responsibility for several requirements are assigned to a "group" of Planning Coordinators, but Planning Coordinator Group (PCG) does not appear in the list of applicable entities. We agree with leaving the PCG entity off of the list. However, without a PCG entity in the list, the applicable requirements should be reworded to make each Planing Coordinator individually responsible for their contribution to the group actions. Suggested wording for each applicable requirement is provided in the response to Question 8.If the drafting team decides to apply requirement responsiblities to a PCG, then NERC should revise the Compliance Registry Criteria to add the PSG and direct the Regional Entities to register the applicable entities to this function. Since regional PSGs have not been formed as legal entities in the past, then going this direction would require PC to establish contracts to form these groups in order to clearly define the compliance and sanction liabilities of each PC in the group. Transmission Owners should be removed because it is redundant with Distribution Provider. Per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner that provides and operates the wires to end-use Load served at transmission voltages must register as a Distribution Provider or transferred the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. Therefore, we suggest the removal of Transmission Owner from the Applicability section. Generator Owners (GO) should be included in the Applicable entities section and requirements should be added that assign GOs the responsibility for providing generator off nominal frequency protection information to the Planning Coordinator and for coordinating any generator off nominal frequency protection with any applicable UFLS program.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability		

Organization	Yes or No	Question 1b Comments:
has been changed to individual Planning Coordinators. **In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.** **This standard has not included requirements for Generator Owners since such requirements have been grouped with other generator requirements in PRC-024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.**		
Ameren	No	It seems that the Transmission Planner would be a better choice than the Planning Coordinator for the design of the UFLS programs. The Transmission Planner is more knowledgeable about the how the load and generation interact and how best to model these impacts on the frequency.
Response: The SDT believes the Planning Coordinator is the appropriate applicable entity because design of an UFLS program should consider the widest possible geographic area. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role, the SDT believes that the Transmission Planners' expertise will be utilized.		
FirstEnergy Corp	No	We support the removal of the Transmission Owner with end-use Load connected to their Facilities. The Distribution Provider entity adequately covers all load that is subject to this standard. The Generator Owner should be added to better coordinate their frequency protection with UFLS.
Response: In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. **This standard has not included requirements for Generator Owners since such requirements have been grouped with other generator requirements in PRC-024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.**		
Xcel Energy	No	We feel 4.3 should be removed. Additionally, we feel that the informal formation of a group for the Planning Coordinators in non-RTO areas is problematic. We feel a new registered entity should be created, perhaps called the Planning Coordinator Group. This group would develop a governing document that spells out roles, responsibilities, etc. like a Reserve Sharing Group does. We feel this approach would best resolve issues surrounding coordination, compliance audits, entity identification in situations of potential non-compliance, penalty assessment, etc. The individual Planning Coordinators would still be required to join a group in their region, per R1. But, the remainder of the requirements should only refer

Organization	Yes or No	Question 1b Comments:
		to the Planning Coordinator Group.If the Regional Entity is not going to play a role in coordinating the Planning Coordinators, then we are unsure how an entity would join a group or attach itself to a group. We feel that in non-RTO areas, the Regional Entity should at least serve as a single point of contact for all Planning Coordinators in that region.
Response: In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. **The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning Coordinators join a group that does not presently exist.**		
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes specifically that data collection and assessments are most effectively carried out at the regional level. However, it is important to note one issue that will have to be dealt with in the regional standard and/or programs is how to account for the small load-serving systems (e.g., less than 25 MW) that are not NERC-registered.
Response: The SDT agrees with the commenter and offers the following observations. Notes 1 and 4 of the NERC Compliance Registry state in part that "The above are general criteria only. The Regional Entity considering registration of an organization not meeting (e.g., smaller in size than) the criteria may propose registration of that organization if the Regional Entity believes and can reasonably demonstrate that the organization is a bulk power system owner, or operates, or uses bulk power system assets, and is material to the reliability of the bulk power system." And that "If an entity is part of a class of entities excluded based on the criteria above as individually being unlikely to have a material impact on the reliability of the bulk power system, but that in aggregate have been demonstrated to have such an impact it may be registered for applicable standards and requirements irrespective of other considerations." The SDT has already received initial feedback from both NERC and FERC staffs that such a condition may exist for implementation of this standard since the effectiveness of an overall UFLS program must consider the entire load. The development of any UFLS program must include some means of providing a mutual/coordinated load shed for "smaller" entities such as agreements by "larger" entities to provide such load shedding.		
Bonneville Power Administration	Yes	BPA will have to have delegation agreements with DP's when BPA is covering their loads with BPA-UFLS relays or through other UFLS armed load in our BAA.
Response: The SDT agrees that the approach the commenter is suggesting is one appropriate way to address the needs, and thanks the commenter for their support.		
ERCOT ISO	Yes	ERCOT ISO believes the Planning Coordinator is the correct responsible entity.
Response: Thank you for your support.		

Organization	Yes or No	Question 1b Comments:
	Yes	I would defer to the opinion of the Planning Coordinators, but am wondering why the RC is not involved. As far as the TO and DP responsibility I see no problem as long as it is clear what data and load tripping is required.
Response: Reliability Coordinators are not included in this standard because this standard addresses only multi-step automatic relay tripping and load shedding that must be planned and implemented in advance. The SDT believes that Planning Coordinators are the appropriate entities for this function. Manual load shedding is not covered by this standard.		
PacifiCorp	Yes	While PacifiCorp agrees that coordination between Planning Coordinators is necessary in order to design and implement an effective UFLS program, it has some concern regarding the assignment of responsibility for compliance with this standard to a currently undefined group of Planning Coordinators. There is no such entity in the Functional Model and it is therefore unclear as to how this group will function and by whom it will be governed. The way the standard is currently drafted raises significant questions regarding how the requirements will be enforced, how a Planning Coordinator will know what group to participate in, how its participation in such group will be evaluated, how disagreements between group participants will be resolved, and which entity, among such group of Planning Coordinators, will be responsible for any potential violations. PacifiCorp recommends that either 1) the SDT assign the UFLS coordination responsibility and governance to the Regional Entity; or 2) the SDT re-draft the standard in such a way that allows Planning Coordinators to assign their compliance responsibility and activity to an agent Planning Coordinator Group similar to the group concept utilized in BAL-002-0 that allows Balancing Authorities to assign compliance responsibility to a Reserve Sharing Group.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
NIPSCO	Yes	The planning groups yes
Response: Thank you for your support.		
Pepco Holdings, Inc – Affiliates	Yes	
Electric Market Policy	Yes	
Edward C. Stein	Yes	
Colmac Clarion	Yes	

Organization	Yes or No	Question 1b Comments:
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
US Army Corps of Engineers	Yes	
Public Service Electric and Gas Company	Yes	
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
ReliabilityFirst Corporation	Yes	
System Protection & Control	Yes	
Ontario Power Generation	Yes	
Luminant Power	Yes	
NextEra Energy Resources, LLC		No comment.

2. The SDT has strived to draft the applicability in a manner that includes all load while avoiding assigning applicability to more than one entity for the same load. The Functional Model indicates the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. Considering the Functional Model definition of Distribution Providers please indicate whether you believe it is necessary to assign applicability to "Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of a Distribution Provider's load".

Summary Consideration: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.

Organization	Yes or No	Question 2 Comments:
Northeast Power Coordinating Council	No	Based on the definition of Distribution Provider in the Functional Model we believe that the applicability should be limited to Distribution Providers. All load should be accounted for by a registered Distribution Provider. The standard should not be written to correct for deficiencies resulting from incorrect registration of entities, and proper registration is vital to the reliability of the UFLS program.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Southern Company	No	The applicability should be assigned to the TO only (not to DP). The Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate, if they choose, to implement the UFLS scheme providing the most selective load tripping, while at the same time, allowing for more efficient aggregation of smaller DPs' load into the overall scheme.

Organization	Yes or No	Question 2 Comments:
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Electric Market Policy	No	The definition of Distribution Provider is adequate.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Midwest ISO Stakeholders Standards Collaborators	No	We do not believe it is necessary to assign applicability to Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of the Distribution Providers load. We believe this clause is describing a distribution provider and these TOs should be registered as DPs. Furthermore, Standards should not attempt to create new classifications of registered entities. This is the function of the compliance registration process.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
SERC UFLS Standards Drafting Team	No	The applicability should be assigned to the TO only (not to DP). The Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.

Organization	Yes or No	Question 2 Comments:
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
MRO NERC Standards Review Subcommittee	No	The MRO NSRS believes that the definition of Distribution Provider assures that there are no gaps or holes in coverage of the applicable load. As noted in the response to Question 1, it is unnecessary to also assign applicability to Transmission Owners with end-use Load connected to their Facilities because according to the NERC Compliance Registry Criteria Rev 5.0 (Sections II.b and III.b.2) these entities must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Kansas City Power & Light	No	No, it is not necessary to include Transmission Provider with end-use load.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
IRC Standards Review Comittee	No	NERC standards and requirements should not attempt to further define the functional entities. For those transmission owners that have facilities that meet the NERC definition of Distribution Provider, they should be registered in the compliance registry as such. If the interpretation of the current definition is that it does not include Transmission Owners with end-use Load connected to their facilities, we recommend the definition of Distribution Provider be updated.The Functional Model does not preclude assigning this responsibility to the Transmission Owners with end-use Load connected to their facilities where such end-use load is not part of a Distribution Provider's load. Excerpt

Organization	Yes or No	Question 2 Comments:
		from Chapter 14 of the Version 4 Functional Model Technical Document, below, describes this process:[When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedance of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.]Loads that are connected to the transmission facilities and where such loads are not part of the DP's loads can and should be curtailed by the TOP action (to relieve constraints) or by the UFLS relays provided by the TOs (to arrest frequency decline).If the SDT is still undecided on this issue, we suggest the SDT consult the FMWG
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Public Service Electric and Gas Company	No	The Distribution Provider can in most cases identify all the load that is included in the UFLS Program.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Central Lincoln	No	But please see Q1b comments.
Response: Please see the response to Q1b comments.		
SPP System Protection and Control Working Group	No	For those transmission owners that have facilities that meet the NERC definition of Distribution Provider, they should be registered in the compliance registry as such.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance		

Organization	Yes or No	Question 2 Comments:
Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Long island power Authority	No	
ReliabilityFirst	No	The Transmision Owner with end use load connected ... is out of line with the NERC Functional Model knowing that if a Transmision Owner has end use load connected, by definition, the Transmision Owner must register as a Distribution Provider. Therefore, using just the Distribution Provider in the UFLS standard is adequate and complete.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Illinois Municipal Electric Agency	No	IMEA believes it is not necessary to assign applicability to the TO function since the NERC Statement of Compliance Registry Criteria (Revision 5.0) already specifies that for end-use customers who are served at transmission voltages, the TO also serves as the DP (i.e., such a TO should already be registered as a DP).
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
American Transmission Company	No	As noted in the response to Question 1, per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner with end-use load connected to their facilities must register as a Distribution Provider or transferred the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. So, all applicable end-use load will be covered by the standard and the assignment of applicability to Transmission Owners with end-use load connected to their facilties is superflous and redundant.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers		

Organization	Yes or No	Question 2 Comments:
and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Hydro-Québec TransEnergie (HQT)	No	Based on the definition of Distribution Provider in the Functional Model we believe that the applicability should be limited to Distribution Providers. All load should be accounted for by a registered Distribution Provider. The standard should not be written to correct for deficiencies resulting from incorrect registration of entities, and proper registration is vital to the reliability of the UFLS program.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
FirstEnergy Corp	No	The Distribution Provider sufficiently covers the end-use load subject to UFLS requirements and we do not believe the Transmission Owner needs to be included within the applicability of this standard.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
CenterPoint Energy	No	For many years, CenterPoint Energy has complied with regional UFLS criteria for distribution load tripping. CenterPoint Energy does not believe it is necessary to include any requirements within PRC-006 for applicability to Transmission Owners and, therefore, recommends deleting Transmission Owner from Requirements 9 and 10. CenterPoint Energy commends the SDT for addressing the difficult issue of Applicability. By definition, Transmission Owners do not serve any load, whether distribution voltage or end-use transmission voltage. There may also be legalities that can preclude a Transmission Owner from serving any load. It would be problematic for a Transmission Owner to determine what transmission end-use load to trip when such loads can be refineries, chemical plants, water plants, and national space agency facilities. Tripping of such loads may have environmental and safety impacts. In addition, a Transmission Owner may not have any ownership of a transmission voltage end-use facility, nor control

Organization	Yes or No	Question 2 Comments:
		over such a facility. CenterPoint Energy believes the NERC Functional Model correctly reflects that Distribution Providers, not Transmission Owners, would be the responsible entity for load tripping.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Xcel Energy	No	We feel 4.3 should be removed.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
We Energies	No	
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes the applicable entities provided for in the proposed standard are appropriate. However, the TRE UFLS SDT believes that the only group that may not be clearly understood to have assigned applicability are self-served customers that can shut down generation and pull from the grid without activating their own underfrequency load shedding. Assigning applicability to Transmission Owners with end-use load may make this clearer but we are not sure it is clear enough for self-served industrials. Additional specific wording to address this may be needed.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. **However, the SDT does not believe that including Transmission Owners in the Applicability clarifies responsibilities for self-served customers. The SDT believes that, from a NERC Reliability Standard perspective, such customers must be addressed and included in an effective UFLS program.**		

Organization	Yes or No	Question 2 Comments:
The SDT is unaware of any provision for such customers to be exempt from functional registration by the Regional Entity. With regard to coordination of generation tripping by frequency level or with regard to load tripping by frequency level, such installations are equally important with regard to their potential impact upon the reliability of the bulk power system.		
Pepco Holdings, Inc - Affiliates	Yes	PHI agrees that including the Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load eliminates the ambiguity that could result if Transmission Owners were not included in the Applicability list.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Bonneville Power Administration	Yes	It addresses DSI and other large loads that are directly connected to the BES.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
ERCOT ISO	Yes	All loads within the region should be accounted for when designing an UFLS program.
Response: The SDT agrees and intends that all load be covered. Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
FRCC Standards & Operations	Yes	We believe that it is necessary to assign applicability to 'Load Serving Entities'. The Compliance Registry Criteria states: Load-serving entity is designated as the responsible entity for facilities that are part of a required

Organization	Yes or No	Question 2 Comments:
Departments		underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system. Therefore their applicability is appropriate.In addition we recommend adding a caveat within the applicability section that reads The TO, LSE or DP may meet these requirements through participation in an aggregated UFLS Program as permitted by the Regional UFLS program. This would allow smaller systems to aggregate load requirements and more effectively meet Regional UFLS requirements. Furthermore, we recommend an additional caveat within the applicability section that reads, "Compliance with an approved Regional Reliability Standard which defines the requirements of the Regional UFLS program satisfies the compliance requirements associated with this continent wide standard." This assumption can be made based on the defined attributes of a Regional Reliability Standard (i. e. Regional Reliability Standards go beyond, add detail to, or implement NERC Reliability Standards. Regional Reliability Standards shall not be inconsistent with or less stringent than NERC Reliability Standards.).
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. The interim changes to the NERC Statement of Compliance Registry were made to reflect concerns about the definition of the LSE as a "facility owning entity" as opposed to the Distribution Provider. As demonstrated in the NERC LSE workshop, currently approved Functional Model and the interim Registry Criteria changes, for standards purposes the DP is the "wires" connection to the electric system and owner of the UFLS tripping equipment. This may be inconsistent with previous usage of the same terms in some parts of the country. The Version 0 applicability for UFLS was set prior to the Registry and determined on the then general understanding of the Functional Model and industry usage. The current Functional Model is much clearer on this issue and designates the DP as the facility owner. Since NERC has stated that the Registry Criteria now has an interim step to correct the issue, it is expected that the Registry Criteria will change as the standards are re-evaluated for appropriateness. The SDT believes that this standard is in line with the direction taken by the interim changes and the approved Functional Model. **The applicability of one standard does not reference another; each standard when approved by FERC or other governmental authorities stands on its own merit. The development of a continent wide standard does not prohibit the development of a regional standard. It is up to the region to decide whether a regional standard can be justified or if a regional variance is appropriate.**		
Florida Municipal Power Agency and Select Members	Yes	Yes, we agree, but, want to be sure the implications are understood. As written, it would seem that the proposed language would make Transmission Owners responsible for adding up the load connected to their system, and if the total load scheduled to trip by UFLS does not meet the percentage of total load connected to that TO required, then, the TO would seem to be the ones responsible for making up the difference. We have to call into question whether

Organization	Yes or No	Question 2 Comments:
		capturing all of the load is worth the effort and whether it truly makes a significant difference to the reliability of the Bulk Electric System.We would suggest the added flexibility of including Load Serving Entities (LSEs) to the applicability section as well as including the ability for LSEs to represent multiple Distribution Providers. The Compliance Registry Criteria states: Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system. Therefore their applicability is appropriate.In addition we recommend adding the ability to aggregate within the applicability section that reads The LSE or DP may meet these requirements through participation in an aggregated UFLS Program. This would allow small systems to aggregate load requirements and more effectively meet Regional UFLS forecast load tripping requirements. The aggregation provides better resolution to the Regional plan requirements. Or alternatively, create a new function that allows aggregation similar to a Reserve Sharing Group.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. The interim changes to the NERC Statement of Compliance Registry were made to reflect concerns about the definition of the LSE as a "facility owning entity" as opposed to the Distribution Provider. As demonstrated in the NERC LSE workshop, currently approved Functional Model and the interim Registry Criteria changes, for standards purposes the DP is the "wires" connection to the electric system and owner of the UFLS tripping equipment. This may be inconsistent with previous usage of the same terms in some parts of the country. The Version 0 applicability for UFLS was set prior to the Registry and determined on general understanding of the Functional Model and industry usage. The current Functional Model is much clearer on this issue and designates the DP as the facility owner. Since NERC has stated that the Registry Criteria now has an interim step to correct the issue. It is expected that the Registry Criteria will change as the standards are re-evaluated for appropriateness. The SDT believes that this standard is in line with the direction taken by the interim changes and the approved Functional Model.		
Cowlitz County PUD	Yes	Yes, but for a different reason: many times the TO will be the owner of the UFLS equipment (e.g. Bonneville Power Administration), not the DP. There are many DP's who do not own UFLS equipment and should not be forced in this position if there is a willing TO to take on the responsibility.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. The Statement of Compliance Registry Criteria can permit small		

Organization	Yes or No	Question 2 Comments:
Distribution Provider exemption from registration and therefore exclusion from implementing UFLS apart from the applicability of this standard.		
Exelon	Yes	Need to verify all end use load participates regardless of supply voltage level.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
AEP	Yes	This is a useful method for identifying those TOs where this situation occurs, instead of making the standard unnecessarily apply to all TOs.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
PacifiCorp	Yes	The simulations done by a group of Planning Coordinators must include all load in designing the UFLS program. However, there should be no obligation that all entities be required to shed any of their load at any particular frequency as long as sufficient load is shed in the area under study. The UFLS program could exempt Distribution Providers with peak loads less than an agreed upon threshold from shedding any load as long as sufficient load is shed in the area under study.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. The Statement of Compliance Registry Criteria can permit small Distribution Provider exemption from registration and therefore exclusion from implementing UFLS apart from the applicability of this standard.		
Ameren	Yes	There may be loads that have no association or relationship with a Distribution Provider that would allow their load to

Organization	Yes or No	Question 2 Comments:
		be interrupted and thus be considered for the UFLS program.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. The SDT assumes that the loads the commenter refers to are served by Transmission Owners.		
Independent Electricity System Operator	Yes	We agree that it is necessary to assign applicability to Transmission Owners with end-use Load connected to their facilities where such end-use load is not part of a Distribution Providers load. This assignment is in principle consistent with the perceived process presented in the Functional Model pertaining to the Transmission Operator having a role to curtail loads that are under its control to relieve transmission constraint. Excerpt from Chapter 14 of the Version 4 Functional Model Technical Document, below, describes this process:[When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedence of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.]Loads that are connected to the transmission facilities and where such loads are not part of the DPs loads can and should be curtailed by the TOP action (to relieve constraints) or by the UFLS relays provided by the TOs (to arrest frequency decline).
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Colmac Clarion	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
US Army Corps of	Yes	

Organization	Yes or No	Question 2 Comments:
Engineers		
NIPSCO	Yes	
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	Yes	
System Protection & Control	Yes	
Ontario Power Generation	Yes	
Luminant Power	Yes	
NextEra Energy Resources, LLC		No comment.

3. The proposed continent-wide standard requires that Planning Coordinators model the trip settings of any generators that trip at or above 58.0 Hz (Requirement R8) when verifying through dynamic simulation that the UFLS program design is adequate to meet the continent-wide performance characteristics specified in Requirement R6.

Do you agree with this approach to ensure that effectiveness of the UFLS program is not jeopardized by units that trip at or above the minimum frequency (58.0 Hz) at which the UFLS program may arrest frequency decline?

Summary Consideration: Most commenters agree that modeling trip settings of generating units is an acceptable approach to ensure that effectiveness of the UFLS program is not jeopardized by units that trip at or above the frequency at which the UFLS program is designed to arrest frequency decline. Some commenters suggested that determining the units to model based only on a frequency threshold would include units unnecessarily. In response to some comments and further SDT deliberations, the standard has been modified to specify, for assessment modeling purposes, generator tripping boundaries as proposed in PRC-024-1, Attachment 1, for which the 58.0 Hz threshold was originally meant as a proxy. Temporary frequency excursions below the UFLS program set points and time delays could occur and the SDT wants to be sure that the assessments do not overlook any generator trip settings just below UFLS set points or just beyond the UFLS relay time delay settings that may still be reached. The standard has been modified to require, in the assessments per R4, the modeling of generator trip settings according to curves as shown in Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1.

Some commenters expressed concern regarding Planning Coordinators maintaining data on generators with trip settings that do not meet the requirements proposed in PRC-024. The SDT notes that per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under- and over-frequency trip settings that fall outside the acceptable boundaries defined by PRC-024-1, Attachment 1 and may include this information in their database. The SDT agrees with commenters that the Generator Owner is already required by draft PRC-024-1 to supply this information to the Planning Coordinator and has removed this requirement from the draft standard.

Organization	Yes or No	Question 3 Comments:
SPP System Protection and Control Working Group	No	What is the basis for 58.0 Hz? If the region's lowest UFLS setting is designed for 58.7 Hz, is 58.0 Hz requirement critical from the Regional UFLS program point of view?
Response: The SDT chose 58.0 Hz as the minimum frequency to observe for purposes of designing a regional UFLS program. This value also coordinates with the under-frequency generator trip curve in PRC-024-1 currently under draft. If a region's lowest UFLS stage is 58.7 Hz, then 58.0 Hz may not be critical. However, it is possible that temporary frequency excursions below the UFLS program set points and time delays could occur and the SDT wants to be sure that the assessments do not overlook any generator trip settings just below UFLS set points or beyond the UFLS relay		

Organization	Yes or No	Question 3 Comments:
settings that may still be reached. Note that the standard has been modified to require, in the UFLS assessments per R4, the modeling of generator trip settings according to curves as shown in Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1.		
MRO NERC Standards Review Subcommittee	No	[This question actually applies to Requirement R7, not R8.]We agree that PCs should model the trip settings of any generators that may be tripped during the simulated operation of the UFLS program. However, the applicable generator trip settings may vary depending on the set points and time delays of the underfrequency relays of the UFLS program for a given island. We suggest that R7.1 be reworded to "that trip at or above the minimum frequency set points and time delays of the applicable island's UFLS program". This approach gives consideration to the time delay aspect and allows the frequency limit to be higher (or lower), if it is permitted by the applicable island's UFLS program.We suggest similar rewording for R7.2, "that trip at or above the maximum frequency set points and time delays of the applicable island's UFLS program".On a related matter, the existing Requirement R7 states "conduct a UFLS assessment . . . through dynamic simulations". Therefore, we suggest that the following rewording for R7, "shall conduct a UFLS assessment . . . that determines whether the UFLS program design meets . . . R6. The assessment shall include: " This would allow other analytical methods, such as the Equivalent Inertia Analysis, to be used to perform an appropriate UFLS assessment. The Equivalent Inertia method can also be used to check for proper coordination between the underfrequecy relay settings and the generator trip settings. R7.1 "Analysis of the trip settings of any generators that . . ."R7.2 "Analysis of the trip settings of any generators that . . ." R7.3 "Analysis of any automatic load restoration that . . ."See response to comment 8 regarding the 58 Hz limit.
Response: The SDT apologizes for the incorrect reference to R8. The SDT agrees with your principle and has modified the standard to be more specific on what generator trip settings must be modeled. Temporary frequency excursions below the UFLS program set points and time delays could occur and the SDT wants to be sure that the assessments do not overlook any generator trip settings just below UFLS set points or just beyond the UFLS relay time delay settings that may still be reached. The standard has been modified to require, in the UFLS assessments per R4, the modeling of generator trip settings according to curves as shown in Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1. Nothing in the standard precludes the use of Equivalent Inertia Analysis in the UFLS design process, but the SDT believes that dynamic simulations are the most dependable means of assessing compliance to the performance characteristics. Equivalent inertia analysis would not include the effects of island initiating disturbances on localized frequency and voltage, inter-machine oscillations, or the particular response of individual unit governors.		
Kansas City Power & Light	No	This question is actually referring to requirement R6. What is the engineering basis for 58Hz? The frequency threshold should be based on the prevention of damage to generating equipment, operating equipment, customer loads, etc. Regardless of frequency threshold, all generator protection settings that involve frequency and voltage should be modeled in the simulation studies for UFLS programs.
Response: The SDT apologizes for the incorrect reference to R8. The engineering basis is coordination of UFLS programs with generator tripping. R6 (now R3) establishes UFLS program requirements that coordinate with the acceptable generator tripping boundary defined by PRC-024-1, Attachment 1. Assessments of UFLS program designs are required to model generator trip settings that fall outside the acceptable boundary		

Organization	Yes or No	Question 3 Comments:
specified in PRC-024-1. Note that the standard has now been modified to define curves above and below which generator underfrequency and overfrequency protection, respectively, must be modeled. These curves are the same as the proposed curves in PRC-024-1, Attachment 1. Please see R4 and Attachments 1 and 2. The SDT disagrees that it is necessary to require in this standard that protection settings involving voltage need to be modeled in UFLS assessments, though that may be advisable when simulating islanding scenarios resulting from severe disturbances.		
Colmac Clarion	No	Some U/F setpoints currently in use above 58.0 Hz were mandated by Generator OEM vice Transmission Operator. All U/F setpoint 'mandates' should be made not to violate design setpoints for specific generators OEM requirements when conducting analysis of setpoints.
Response: The proposed standard does not preclude settings above 58.0 Hz; it only requires such settings be modeled by the Planning Coordinators in their UFLS assessments. Please refer to Project 2007-09 and PRC-024-1 for requirements on generator under-frequency settings.		
US Army Corps of Engineers	No	Without actually testing the UFLS, how do you know that the simulation testing adequately represents real world events? There needs to be more concrete assurance or testing of the generation side to show that the unis will not trip off. I realize that this assurance should be covered under the MOD Reliability Standards, but I don't think it has been completely addressed.
Response: There is always a question about how well simulation studies represent the real world. Model validation and event replication studies over several decades have increased industry confidence that simulation studies can, in principle, reasonably represent the dynamic behavior of real world power systems. As with any study, assumptions need to be carefully reviewed and validated. The SDT is aware that causes other than frequency-sensing relays may also trip generation outside the acceptable tripping boundaries being proposed in draft PRC-024-1, Attachment 1. Unfortunately, you are right in that this possibility is not being addressed in this standard. The SDT recommends that this matter be brought to the attention of the Project 2007-09, Generator Verification SDT responsible for PRC-024-1.		
NIPSCO	No	The existing trip points with out time delay is 58.2 - To protect against turbine blade damage.I believe any under frequency event that allows the frequency to get to 58 HZ is to late/ and to slow.
Response: The SDT disagrees. While it is true that ECAR Document 3 listed 58.2 Hz as the point to expect immediate generator tripping, according to major generator manufacturer's documents, generators can tolerate frequency excursions for limited time below this level. Please refer to Project 2007-09 and PRC-024-1.		
Public Service Electric and Gas Company	No	No, however, while the effort to determine if the UFLS program is effective if generators trip at or above a minimum frequency, we are not sure that any simulations are accurate enough to validate this. Every event is different, but if it can be accurately modeled, then it is a good approach.
Response: There is always a question about how well simulation studies represent the real world. Model validation and event replication studies		

Organization	Yes or No	Question 3 Comments:
over several decades have increased industry confidence that simulation studies can, in principle, reasonably represent the dynamic behavior of real world power systems. As with any study, assumptions need to be carefully reviewed and validated.		
American Transmission Company	No	[This question actually applies to Requirement R7, not R8.]We agree that PCs should model the trip settings of any generators that may be trip during the simulated operation of the UFLS program. The applicable generator trip settings will depend on the set points and time delays of the underfrequency relays in the UFLS program. We suggest that R7.1 be reworded to "that trip at or above the minimum frequency set points and time delays of the applicable island's UFLS program". This approach gives consideration to the time delay aspect and allows the frequency limit to be higher (or lower), if it is permitted by the applicable island's UFLS program.We suggest similar rewording for R7.2, "that trip at or above the maximum frequency set points and time delays of the applicable island's UFLS program".On a related matter, the root Requirement R7 states "conduct a UFLS assessment . . . through dynamic simulations". However, other analytical methods, such as Equivalent Inertia Anaysis, can also be used to perform an appropriate UFLS assessment and may check for proper coordination between the underfrequecy relay settings and the generator trip settings. Therefore, we suggest that the following rewording for R7, "shall conduct a UFLS assessment . . . that determines whether the UFLS program design meets . . . R6. The assessment shall inlcude:"R7.1 "Analysis of the trip settings of any generators that . . ."R7.2 "Analysis of the trip settings of any generators that . . ." R7.3 "Analysis of any automatic load restoration that . . ."See the response to Question 8 for comment on the 58.0 Hz and 61.8 Hz limits.
Response: The SDT apologizes for the incorrect reference to R8. The SDT agrees with your principle and has modified the standard to be more specific on what generator trip settings must be modeled. Temporary frequency excursions below the UFLS program set points and time delays could occur and the SDT wants to be sure that the assessments do not overlook any generator trip settings just below UFLS set points or just beyond the UFLS relay time delay settings that may still be reached. The standard has been modified to require, in the UFLS assessments per R4, the modeling of generator trip settings according to curves as shown in Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1. Nothing in the standard precludes the use of Equivalent Inertia Analysis in the UFLS design process, but the SDT believes that dynamic simulations are the most dependable means of assessing compliance to the performance characteristics in R6. Equivalent inertia analysis would not include the effects of island initiating disturbances on localized frequency and voltage, inter-machine oscillations, or the particular response of individual unit governors.		
FirstEnergy Corp	No	The Planning Coordinator should be required to model somewhat below the 58.0 Hz level, we suggest down to 57.5 Hz, so that a sensitivity analysis is performed evaluating the severity of frequency disturbance that is not fully arrested at or above the 58 Hz level. This information could be used to assess if additional load dropping may be needed for more severe frequency events.
Response: The standard has been modified to address your comment. The SDT has defined curves above and below which generator underfrequency and overfrequency protection, respectively, must be modeled. See R4 and Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1. As such, the minimum generator trip threshold that must be modeled is now 57.8 Hz, which the SDT		

Organization	Yes or No	Question 3 Comments:
believes provides adequate margin.		
IRC Standards Review Committee	Yes	We agree but we think you meant R7, not R8. And assuming that the expected loss of generation (for generators tripping at or above 58.0 Hz) is to be compensated by selecting an additional, equivalent amount of load in the UFLS program, the additional load reduction would also need to be simulated.
Response: Thank you for your support. The SDT apologizes for the incorrect reference to R8. The SDT agrees that any extra load shedding necessary for the UFLS program to comply with the performance characteristics in R6 (now R3) would need to be simulated.		
Cowlitz County PUD	Yes	This seems fair to me. There is no mandate not to allow trip settings above 58 Hz, but there must be very good reasons for such settings, and that such settings will not require greater than necessary load shedding efforts to stabilize the BPS. DPs and LSEs are sensitive to reliable service to their customers. Unnecessary load shedding would add insult to injury.
Response: Thank you for your support. Per R5 and R6 of the first draft of PRC-024-1, Generator Owners will need to document, subject to peer review, any generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1.		
Independent Electricity System Operator	Yes	We agree but I think you meant R7, not R8. And assuming that the expected loss of generation (for generators tripping at or above 58.0 Hz) is to be compensated by selecting an additional, equivalent amount of load in the UFLS program, the additional load reduction would also need to be simulated. If this requirement is to be added, depending on how this is to be complied with the Applicability Section may need to be expanded.
Response: Thank you for your support. The SDT apologizes for the incorrect reference to R8. The SDT agrees that any extra load shedding necessary for the UFLS program to comply with the performance characteristics in R6 (now R3) would need to be simulated. The applicability section does not need to be expanded because Planning Coordinators would still be the applicable entities to demonstrate compliance with R4 in R5.		
Xcel Energy	Yes	The dynamic simulation would need to include any small generators (<20MVA or <75MVA aggregate) that are not required to register, but together, could have a material impact on the BES. Additionally, it would need to be clear who is responsible for ensuring those material impacts are included in models/simulations.
Response: Thank you for your support. Although there are differing views on this question, the SDT has decided that it is sufficient to require the modeling of generator trip settings on small generators consistent with the NERC Statement of Compliance Registry Criteria. Please see R4. The Planning Coordinators are the responsible entity for ensuring that material impacts are included in UFLS assessments per R4 and R5.		
TRE UFLS Standard Drafting Team	Yes	It would appear to be essential that the Planning Coordinators data base include trip settings and time delay to tripping for resources that trip above the 58.0 Hz point. The effective simulation and design of a regional UFLS plan must

Organization	Yes or No	Question 3 Comments:
		definitively show the targeted islanding of the region. By not including the modeling of the trip points and time delays for machines that trip above 58.0, Hz, the Planning Coordinator cannot ensure the simulation and plan for effective and survivable islands that can be forecasted to exist post separation. The time criteria in R6.2, particularly the first two cumulative steps, require the effective modeling of machines set to trip above 58.0 Hz.
Response: Thank you for your support. Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1, and may include this in their database. Note that the standard has been modified to require, in the UFLS assessments per R4, the modeling of generator trip settings according to curves as shown in Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1.		
Southern Company	Yes	The generators must be modeled to reflect the way they perform.
Response: Thank you for your support.		
ERCOT ISO	Yes	ERCOT ISO believes it is necessary to consider all automatic tripping schemes or protection schemes when designing an UFLS program to meet the requirements of this standard. However, explicit modeling of generator frequency trip settings (above 58.0Hz/below 61.8Hz) should only be required when they are relevant to satisfying the performance requirements of the standard (i.e. if generator trips are initiated for excursions lasting less than 30 seconds).
Response: Thank you for your support. The standard has been modified to address your comment by defining curves above and below which generator underfrequency and overfrequency protection, respectively, must be modeled. These curves are the same as the proposed curves in PRC-024-1, Attachment 1. Please see R4 and Attachments 1 and 2.		
Midwest ISO Stakeholders Standards Collaborators	Yes	Generation owners certainly have the right to set relays to protect their equipment from damage and are actually speeding restoration by doing so. Any units that will trip before frequency triggers UFLS relays should certainly be considered in the dynamic simulations.
Response: Thank you for your support.		
Luminant Power	Yes	Luminant agrees with the UFLS SDT that the Planning Coordinators should model the generators that would trip at or above 58.0 Hz, as required by R7. However, Requirement R8 of PRC-006 requires the Planning Coordinator to maintain a database of relay information only from Transmission Owners and Distribution Providers. The Planning Coordinator database in Requirement R8 should also include relay information from Generator Owners. The UFLS SDT does not need to include a requirement in PRC-006 for Generator Owners to provide the information, as the draft NERC Standard PRC-024 requires Generator Owners to provide frequency and voltage relay setting information to the Planning Coordinator.

Organization	Yes or No	Question 3 Comments:
Response: Thank you for your support. Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. The SDT agrees that the Generator Owner is already required by draft PRC-024-1 to supply this information to the Planning Coordinator and has removed this requirement from the draft standard.		
Ameren	Yes	Yes, such generators should have their trip settings modeled to determine the additional load that must be shed because they do not meet performance characteristics. The cost to include this additional load shed should be allocated to these generators.
Response: Thank you for your support. Cost allocation is outside the scope of reliability standards.		
SERC UFLS Standards Drafting Team	Yes	he generators must be modeled to reflect the way they perform.
Response: Thank you for your support.		
Hydro-Québec TransEnergie (HQT)	Yes	See also our answer to Q8 in regards to the minimum frequency treshold.
Response: Thank you for your support.		
AEP	Yes	Please note that the reference to R8 in the question appears to an error.
Response: Thank you for your support. The SDT apologizes for the incorrect reference to R8.		
Pepco Holdings, Inc – Affiliates	Yes	
Bonneville Power Administration	Yes	
Northeast Power Coordinating Council	Yes	
Electric Market Policy	Yes	

Organization	Yes or No	Question 3 Comments:
FRCC Standards & Operations Departments	Yes	
Florida Municipal Power Agency and Select Members	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
Central Lincoln	Yes	
Long island power Authority	Yes	
Exelon	Yes	
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	Yes	
System Protection & Control	Yes	

Organization	Yes or No	Question 3 Comments:
ReliabilityFirst	Yes	
Ontario Power Generation	Yes	
We Energies	Yes	
PacifiCorp	Yes	
NextEra Energy Resources, LLC	Yes	

4. The SDT added a requirement that requires the Planning Coordinators model, in the five year assessments, any automatic load restoration that is designed to assist in stabilizing system frequency (Requirement R9). The team decided to add this requirement as a result of a comment during the first posting. Do you agree that this requirement is necessary for reliability?

Summary Consideration:

Most entities support this requirement.

Some want exceptions to be allowed to exclude this modeling from the program design if the automatic load restoration is "insignificant". Some feel this requirement does not go far enough to include ***ALL*** automatic load restoration schemes which may impact UFLS, not just the ones ***designed*** to impact UFLS. The SDT believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled. The SDT modified the requirement (now Requirement R4, Part 4.7 in the revised standard) from "any automatic load restoration that is designed to assist in stabilizing frequency" to "any automatic load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment."

Some feel that automatic load restoration is generally a bad idea for use with UFLS. The SDT noted that the proposed standard does not require the use of automatic load restoration schemes and acknowledges this may not be a practical method to stabilize some systems. However, where automatic load restoration schemes are utilized a failure to consider them in assessments of the UFLS program design may result in unintended consequences during actual UFLS events. The SDT included modeling of automatic load restoration in UFLS program assessments to identify any unintended consequences of using automatic load restoration.

Organization	Yes or No	Question 4 Comments:
Alabama Municipal Electric Authority	No	If the automatic load was induced by inductors I would have voted yes because this is part of good planning. I voted "no" because there is no way to determine or predict that "all" of the load for a load restoration activity would be "available" if the automatic load restoration was for user or customer load.
Response: The SDT makes no reference to the origination of the load to be included for automatic restoration in the UFLS program design. Where such automatic load restoration is utilized, the Planning Coordinators are required to model, in their UFLS program assessments, the actual scheme as implemented.		
Public Service Electric and Gas Company	No	It would not seem practical to consider automatic load restoration as a method to stabilize a system.

Organization	Yes or No	Question 4 Comments:
Response: The SDT is not requiring the use of automatic load restoration schemes and acknowledges this may not be a practical method to stabilize some systems. However, where automatic load restoration schemes are utilized a failure to consider them in assessments of the UFLS program design may result in unintended consequences during actual UFLS events.		
Ameren	No	Each region should be required to identify the amount of automatic load restoration in their region that is designed to assist in stabilizing system frequency. If the region determines that this amount is insignificant and will not materially impact the design of the region's UFLS program, then they should be allowed to exclude this load from their simulations.
Response: The SDT believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled.		
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes that successful deployment of a UFLS is dependent on two concepts. The first is automatic reaction of the UFLS when frequency triggers its response to dump load. The second is load shall not be brought back until the Reliability Coordinator instructs each entity to do so in whatever order is appropriate for adequate recovery. Therefore modeling of any applicable automatic load restoration should be included in a region's UFLS program.
Response: Thank you for your support.		
Bonneville Power Administration	Yes	It addresses automatic load restoration for frequency over-shoot.
Response: Thank you for your support.		
Northeast Power Coordinating Council	Yes	We believe that any automatic action that impacts recovery and stabilization of frequency must be modeled.
Response: Thank you for your support.		
Southern Company	Yes	Yes, but with the ability to specify exceptions. Each regional entity should be required to identify the amount of automatic load restoration in their region that is designed to assist in stabilizing system frequency. If the region determines that this amount is insignificant (e.g. 1%) and will not materially impact the design of the region's UFLS scheme, then they should be allowed to exclude this load from their simulations.
Response: The SDT believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the		

Organization	Yes or No	Question 4 Comments:
duration of the simulations run for the assessment should be modeled.		
ERCOT ISO	Yes	At this time ERCOT ISO does not know of any automatic load restoration schemes within the ERCOT Interconnection. But as previously stated in question 3, it is necessary to consider all automatic tripping schemes when developing an UFLS program to meet the requirements of this standard, and therefore ERCOT ISO agrees this is necessary.
Response: Thank you for your support.		
Electric Market Policy	Yes	However, Question 4 reference to Requirement R9 should be R7.
Response: The SDT apologizes for the incorrect reference to R9.		
Midwest ISO Stakeholders Standards Collaborators	Yes	Generally, automatic load restoration is a bad idea. It could interfere with restoration. What if too much load is restored and actually causes frequency to decline significantly?
Response: The SDT included modeling of automatic load restoration in UFLS program assessments to identify any unintended consequences of using automatic load restoration.		
SERC UFLS Standards Drafting Team	Yes	Yes, but with the ability to specify exceptions. Each regional should be required to identify the amount of automatic load restoration in their region that is design to assist in stabilizing system frequency. If the region determines that this amount is insignificant (e.g. 1%) and will not materially impact the design of the region's UFLS scheme, then they should be allowed to excluded this load from their simulations.
Response: The SDT believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled.		
MRO NERC Standards Review Subcommittee	Yes	This question actually applies to Requirement R7.3, not R9.]We agree that any automatic load restoration that is designed to assist in stabilizing the system frequency should be modeled in the ULFS Program assessment.
Response: The SDT apologizes for the incorrect reference to R9. Thank you for your support.		

Organization	Yes or No	Question 4 Comments:
IRC Standards Review committee	Yes	We agree with this requirement but believe there should be more specific language on what schemes should be included in the study. There may also be automatic load restoration schemes that have an impact on stabilizing system frequency but was not installed with that intent. The study should also consider the effects of these automatic restoration schemes. Again, we think you meant R7, not R9. We agree. Any pre-determined actions such as tripping of additional load for generator tripping at or above 58.0 Hz as discussed in Q3, above, and automatic restoration of load, etc. should be modeled and assessed via simulations to evaluate frequency performance of potential islands.
Response: The SDT believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled. **The SDT apologizes for the incorrect reference to R9.** **Thank you for your support.**		
Cowlitz County PUD	Yes	You meant Requirment R7.3? This seems to be an excellent idea to me. Anything that both stabilizes the BPS and improves on customer service is a winner.
Response: The SDT apologizes for the incorrect reference to R9. Thank you for your support.		
US Army Corps of Engineers	Yes	Modeling automatic load restoration on a 5 year cycle should capture the changes/modifications that the individual Registered Entities have done to their system. Too often the minor tweaks to a system get lost in the cracks and the cumulative modifications do have an impact on system studies.
Response: Thank you for your comments.		
SPP System Protection and Control Working Group	Yes	We agree with this requirement but believe there should be more specific language on what schemes should be included in the study. There may also be automatic load restoration schemes that have an impact on stabilizing system frequency but was not installed with that intent. The study should also consider the effects of these automatic restoration schemes.
Response: The SDT agrees and believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled.		

Organization	Yes or No	Question 4 Comments:
Exelon	Yes	It should be clear only those restoration systems designed to stabilize system frequency should be included in the standard. Requirement 9 in the proposed standard does not appear to be related to automatic load restoration systems.
Response: The SDT agrees and believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled. **The SDT apologizes for the incorrect reference to R9.**		
Arkansas Electric Cooperative Corporation	Yes	It stands to reason that any tripping or restoration schemes that are automatic should be modeled and included in the simulations.
Response: Thank you for your support.		
Hydro-Québec TransEnergie (HQT)	Yes	HQT believe that any automatic action that impacts recovery and stabilization of frequency must be modeled.
Response: Thank you for your support.		
AEP	Yes	Please note that we are responding in the context of requirement 7.3, not requirement 9. There appears to be a error in the requirement 9 reference.
Response: The SDT apologizes for the incorrect reference to R9.		
American Transmission Company	Yes	[This question actually applies to Requirement R7.3, not R9.] We agree that any automatic load restoration that is designed to assist in stabilizing the system frequency should be modeled in the ULFS Program assessment. On the other hand, we suggest that automatic load restoration should be avoided whenever possible.
Response: The SDT apologizes for the incorrect reference to R9. **Thank you for your support.**		
Independent Electricity System	Yes	Again, we think you meant R7, not R9. We agree.

Organization	Yes or No	Question 4 Comments:
Operator		Any pre-determined actions such as tripping of additional load for generator tripping at or above 58.0 Hz as discussed in Q3, above, and automatic restoration of load, etc. should be modeled and assessed via simulations to evaluate frequency performance of potential islands.
Response: The SDT apologizes for the incorrect reference to R9. **Thank you for your support.**		
Xcel Energy	Yes	(We assume you meant R7, not R9.)
Response: The SDT apologizes for the incorrect reference to R9.		
Kansas City Power & Light	Yes	
NIPSCO	Yes	
Central Lincoln	Yes	
Long island power Authority	Yes	
ReliabilityFirst Corporation	Yes	
System Protection & Control	Yes	
ReliabilityFirst	Yes	
Ontario Power Generation	Yes	
We Energies	Yes	

Organization	Yes or No	Question 4 Comments:
PacifiCorp	Yes	
NextEra Energy Resources, LLC	Yes	
Luminant Power	Yes	
FirstEnergy Corp	Yes	
Pepco Holdings, Inc - Affiliates	Yes	
FRCC Standards & Operations Departments	Yes	
Florida Municipal Power Agency and Select Members	Yes	
Colmac Clarion	Yes	
City of Bedford	Yes	

5. **In the first posting, the Characteristics of UFLS Regional Reliability Standards required that UFLS programs be designed to limit the potential for overexcitation (V/Hz) of power system equipment at all Bulk Electric System buses. Based on industry comments, the SDT has revised this requirement in the proposed continent-wide standard to apply only at generator buses and generator step-up transformer high-side buses associated with individual generating units greater than 20 MVA (gross nameplate rating) and generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) that are directly connected to the BES. The SDT believes this change better addresses the need to have UFLS programs designed to coordinate with protection that may trip generators during an underfrequency event. Do you agree with this change?**

Summary Consideration:

The SDT has considered industry input regarding the V/Hz performance characteristic. The majority of comments from the industry supported the changes made to this requirement in the second posting.

However, the team identified the need to make two clarifying changes to the requirement. Based on its own review of the requirement the SDT decided to remove any ambiguity as to whether modeling is required when all or only one threshold is met by combining R 6.4.1 and R6.4.2 with “OR” (now Part 3.3.1 of R3). Based on a comment the SDT also added a third threshold in Part 3.3.1 of R3 to clarify our intent to include wind generation, by adding “Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.” Thus, the applicability is limited to locations at which individual generating units greater than 20 MVA (gross nameplate rating) or generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) are directly connected to the BES or any facility consisting of one or more units that are connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT also has modified Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.

The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from conservative simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard, the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.

Organization	Yes or No	Question 5 Comments:
NIPSCO	No	4 seconds is too long.
Response: The proposed point provides 0.2 Hz margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. The SDT believes that decreasing the time to less than four seconds is not necessary to coordinate the UFLS program with the generator protection requirements in PRC-024 and would place an unnecessary burden on the group of Planning Coordinators responsible for the UFLS program design.		
Midwest ISO Stakeholders Standards Collaborators	No	Please provide the technical justification for this performance criterion. We would like to add the statement "Unless generation capability or protection warrants or allows for a lower limit" to the end of the requirement. In the MRO region, this would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load. In these areas, when shedding that much load the frequency would drop below 58.2 Hz for longer than 4 seconds. We understand the SDT wants to ensure load shedding programs achieve quick frequency recovery and minimize underfrequency exposure. However we do not feel this requirement is the right way to go about that. This type of criteria is overly specific and should not be in the NERC standard. The recently developed MRO UFLS program which sheds 30% of system load appears to meet this criteria, but the Canadian portions of MRO which have higher load shedding requirements are unlikely meet this criteria. Aggressive load shedding programs in general will probably not satisfy this requirement. Frequency recovery, overall load shedding performance, and coordination with generation protection, should all be evaluated at the regional level by those who do the technical analysis of regional load shedding programs. In addition to study work, a lot of common sense needs to be applied. Several things need to be discussed to clarify our position.
Response: This criterion was selected to provide margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. The SDT does not believe it is necessary to modify the requirement as suggested because the performance characteristics in R6 (R4 in the revised standard) of the draft PRC-006 standard would NOT apply to load-generation imbalances over 25 percent. A UFLS program capable of shedding more than 25 percent of a system's load would only need to comply with the performance characteristics up to a 25 percent load-generation imbalance. Beyond a 25 percent load-generation imbalance, the group of Planning Coordinators within a region would not be subject to these requirements and could devise other performance characteristics that would apply under load-generation imbalance scenarios greater than 25 percent. The SDT did, however, modify the underfrequency performance characteristic, as shown in the Attachment 1 Underfrequency Curves, noting that some entities could have difficulty recovering frequency within 30 seconds with a 25 percent imbalance. This modification to the performance characteristic still maintains a 0.2 Hz margin with the generator tripping limitations proposed by the Generator Verification STD. **The SDT understands the concern over bigger sub-regional UFLS programs. The SDT recognizes that Planning Coordinators in a region with a 60 percent capable UFLS program, for example, may have trouble complying with the performance characteristics even under a 25 percent load-generation imbalance scenario. The SDT is not convinced that it would be impossible to comply, but can see that it could be more difficult.**		

Organization	Yes or No	Question 5 Comments:
Assessments that demonstrate the reliability objective of PRC-006 can be met without meeting the performance characteristics in Requirement R6 (R4 in the revised standard) could be used to support a request for a regional variance.		
MRO NERC Standards Review Subcommittee	No	Please provide the technical justification for this performance criteria. We suggest the addition of the statement "Unless generation capability or protection warrants or allows for a lower limit" to the end of Requirement R6.2. In the MRO region, this qualification would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load to achieve reasonable frequency recovery in these islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable. On a related note, we suggest the addition of the statement "Unless generation capability or protection warrants or allows for a higher limit" to the end of Requirement R6.3, if the impacts of island equipment are acceptable.
Response: This criterion was selected to provide margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. The SDT does not believe it is necessary to modify the requirement as suggested because the performance characteristics in R6 of the draft PRC-006 standard (R4 in the revised standard) would NOT apply to load-generation imbalances over 25 percent. An UFLS program capable of shedding more than 25 percent of a system's load would only need to comply with the performance characteristics up to a 25 percent load-generation imbalance. Beyond a 25 percent load-generation imbalance, the group of Planning Coordinators within a region would not be subject to these requirements and could devise other performance characteristics that would apply under load-generation imbalance scenarios greater than 25 percent. The SDT did, however, modify the underfrequency performance characteristic, as shown in the Attachment 1 Underfrequency Curves, noting that some entities could have difficulty recovering frequency within 30 seconds with a 25 percent imbalance. This modification to the performance characteristic still maintains a 0.2 Hz margin with the generator tripping limitations proposed by the Generator Verification STD. **The SDT understands the concern over bigger sub-regional UFLS programs. The SDT recognizes that Planning Coordinators in a region with a 60 percent capable UFLS program, for example, may have trouble complying with the performance characteristics even under a 25 percent load-generation imbalance scenario. The SDT is not convinced that it would be impossible to comply, but can see that it could be more difficult. Assessments that demonstrate the reliability objective of PRC-006 can be met without meeting the performance characteristics in Requirement R6 (R4 in the revised standard) could be used to support a regional variance.**		
Kansas City Power & Light	No	Do not have a problem with a frequency threshold or duration, however, 58.2Hz and 4 seconds sounds arbitrary. UFLS systems have been in place for years and would be very difficult and expensive to modify to meet the criteria stated here. To justify any need to go to that expense, it is important to establish the engineering basis for this criteria. What is the engineering basis for the 58.2Hz and 4 seconds?
Response: The proposed point was selected to provide 0.2 Hz margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. Based on industry input the SDT has replaced the discrete points in the proposed standard with a continuous curve that provides consistent 0.2 Hz margin between 0 and 60 seconds. The SDT does not anticipate that existing UFLS programs will need to be		

Organization	Yes or No	Question 5 Comments:
redesigned to meet this requirement for load-generation imbalances up to 25 percent. However, the group of Planning Coordinators in a region could pursue a variance if their existing UFLS program does not meet the requirement.		
FirstEnergy Corp	No	The requirement does not exactly match those in PRC-024-1 (Attachment 1) on generator frequency characteristics. In fact, reliability would be better served if the frequency requirements for generators was in PRC-006 rather than PRC-024. For UFLS to be effective, it is a fundamental concept that generation stay connected long enough for load shedding to fully occur. By separating these requirements into different standards, it discounts the need to balance load and generation in a stressed system. PRC-024 allows GO's to be granted exceptions to meeting a fairly generous frequency characteristic but there are no assurances that an equivalent load is shed to balance these exceptions.
Response: The SDT's intent is to provide margin to minimize the risk of generators tripping prematurely during an underfrequency event. Based on industry comment, the SDT has clarified this requirement by replacing the discrete points in the proposed standard with a continuous curve that provides a consistent 0.2 Hz margin between 0 and 60 seconds. While the SDT recognizes that regional criteria traditionally have included underfrequency load shedding and generator trip limits in a single document, this has the disadvantage of spreading generator requirements across multiple standards. The SDT believes system reliability can be maintained as long as the UFLS performance characteristics and the generator trip limits are coordinated regardless of the standards in which these requirements reside.		
Duke Energy	No	We agree this change better coordinates with PRC-024.If coordination with PRC-024 is the ultimate goal, it seems a simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.) The stair step created by the proposed method greatly reduces the area available above the PRC-024 limit.[SERC UVLS team see chart below]Even with the added requirement, the UFLS curve still does not coordinate with the PRC 024 curve at 59.5 Hz. If the 59.3 Hz proposed by PRC-006 is maintained, then it seems PRC-024 should be approximately 0.1 Hz lower, 59.2 Hz. Otherwise, the upper limit for PRC-006 must be increased to coordinate with the PRC-024 curve (e.g. increase by 0.3 Hz to 59.6 Hz). Similarly, the upper requirement does not coordinate with PRC-024 out in time.
Response: Thank you for your support. The SDT has adopted an approach that provides a constant offset of 0.2 Hz between 0 and 60 seconds.		
Exelon	No	This should be left up to the regions. Load trip set points are left up to the Regions and thus so should generating unit settings. Unit coordination requirements should be part of the PRC standards (PRC-001 and PRC-024). This requirement leaves the responsibilities of attaining this goal ambiguous. It would not be appropriate to base compliance on an entity performing a study on the study outcome.
Response: The SDT agrees that unit coordination requirements should be established in PRC-024 and notes that the proposed UFLS standard does not establish requirements for generator trip settings. The proposed UFLS standard requires the group of Planning Coordinators within a		

Organization	Yes or No	Question 5 Comments:
region to design and establish the requirements for the UFLS program to coordinate with the generator requirements established in PRC-024.		
American Transmission Company	No	Please provide the industry with the technical justification for this performance criteria.We would like to add the statement "Unless generation capability or protection warrants or allows for a lower limit" to the end of Requirement R6.2 and R6.3. In the MRO region, this qualification would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load to achieve reasonable frequency recovery in these islands. In these areas, the shedding this quantity of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generators in these islands are acceptable.
Response: This criterion was selected to provide margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. The SDT does not believe it is necessary to modify the requirement as suggested because the performance characteristics in R6 of the draft PRC-006 standard (R4 in the revised standard) would NOT apply to load-generation imbalances over 25 percent. An UFLS program capable of shedding more than 25 percent of a system's load would only need to comply with the performance characteristics up to a 25 percent load-generation imbalance. Beyond a 25 percent load-generation imbalance, the group of Planning Coordinators within a region would not be subject to these requirements and could devise other performance characteristics that would apply under load-generation imbalance scenarios greater than 25 percent. The SDT did, however, modify the underfrequency performance characteristic noting that some entities may have difficulty recovering frequency within 30 seconds with a 25 percent imbalance. This modification to the performance characteristic still maintains a 0.2 Hz margin with the generator tripping limitations proposed by the Generator Verification STD. **The SDT understands the concern over bigger sub-regional UFLS programs. The SDT recognizes that Planning Coordinators in a region with a 60 percent capable UFLS program, for example, may have trouble complying with the performance characteristics even under a 25 percent load-generation imbalance scenario. The SDT is not convinced that it would be impossible to comply, but can see that it could be more difficult. Assessments that demonstrate the reliability objective of PRC-006 can be met without meeting the performance characteristics in Requirement R6 (R4 in the revised standard) could be used to support a regional variance.**		
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT agrees that the UFLS program should coordinate with the performance requirements of the Generation Verification Project (PRC-024-1). The requirement for not remaining below 58.2 Hz for greater than four seconds appears to be within the No Trip Zone area of the Off Normal Frequency Capability Curve in Attachment 1 of PRC-024-1.
Response: Thank you for your support.		
Northeast Power Coordinating Council	Yes	We believe it is important to remove this apparent miscoordination between the generator tripping requirements in PRC-024 and the UFLS program performance requirements in PRC-006.
Response: Thank you for your support		

Organization	Yes or No	Question 5 Comments:
ERCOT ISO	Yes	ERCOT ISO agrees that the UFLS program should coordinate with the performance requirements of the Generation Verification Project (PRC-024-1). The requirement for not remaining below 58.2 Hz for greater than four seconds appears to be within the No Trip Zone area of the Off Normal Frequency Capability Curve in Attachment 1 of PRC-024-1.
Response: The SDT appreciates your support.		
IRC Standards Review Committee	Yes	We do not have a concern with this requirement if the 0.2 Hz above 58.0 Hz is intended as a margin/buffer to ensure generators do not trip pre-maturely.
Response: The SDT's intent is to provide margin to minimize the risk of generators tripping prematurely during an underfrequency event. The SDT thanks you for your comment.		
Colmac Clarion	Yes	Agree that it is a reasonable setpoint for consistent evaluation/simulation; may not be reasonable as a 'limit' after evaluation is complete.
Response: The proposed point was selected to provide 0.2 Hz margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. Based on industry input the SDT has replaced the discrete points in the proposed standard with a continuous curve that provides consistent 0.2 Hz margin between 0 and 60 seconds.		
Alabama Municipal Electric Authority	Yes	The SDT should consider changing the four seconds to six seconds because of the data scanning requirements of other generator functions such as automatic generation control.
Response: Thank you for your support. The proposed point provides 0.2 Hz margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. The SDT believes that increasing the time to six seconds would not provide adequate margin to minimize the risk of generators tripping prematurely during an underfrequency event.		
Independent Electricity System Operator	Yes	We do not have a concern with this requirement if the 0.2 Hz above 58.0 Hz is intended as a margin/buffer to ensure generators do not trip pre-maturely. However, we do have a concern with R6.3.During the 2003 blackout, the overfrequency limits in R6.3 were violated without any reported adverse effects on the BES. Why are the overfrequency limits needed? If they are not needed to protection equipment, then they should be removed.
Response: Thank you for your comments. The SDT has developed the overfrequency characteristic in Requirement R6.3 to coordinate with the overfrequency trip setting limits proposed in PRC-024. The trip setting limits were developed by the Generator Verification SDT based on the withstand capabilities of generating units. The concern with operation of generating units at off-nominal frequency is the cumulative fatigue effect, so it is possible that generating units experienced significant loss of life on August 14, 2003 even if the adverse effects were not readily		

Organization	Yes or No	Question 5 Comments:
observable immediately after this event.		
Xcel Energy	Yes	We support the philosophy that load shedding should occur prior to generation tripping. We feel it is important to keep these two projects coordinated.
Response: Thank you for your support.		
Hydro-Québec TransEnergie (HQT)	Yes	HQT believe it is important to remove this apparent miscoordination between the generator tripping requirements in PRC-024 and the UFLS program performance requirements in PRC-006.See also our answer to Q8 in regards to frequency treshold.
Response: Thank you for your support. Please see also our response to your comment on Question 8.		
Hydro-Québec TransEnergie (HQT)	Yes	HQT believe it is important to remove this apparent miscoordination between the generator tripping requirements in PRC-024 and the UFLS program performance requirements in PRC-006.See also our answer to Q8 in regards to frequency treshold.
Response: Thank you for your support. Please see also our response to your comment on Question 8.		
PacifiCorp	Yes	Coordination with PRC-024 is very important. PacifiCorp supports this change.
Response: Thank you for your support.		
Ameren	Yes	It is a step in the right direction but additional modifications to the performance characteristics are needed to coordinate effectively with PRC-024. When viewing the frequency and time limits in PRC-024 simultaneously with this draft standard in a graphical manner, there are regions of frequency and time duration for which it is permitted for the generators to operate, but for which it is not permitted for the system as a whole to operate.
Response: The SDT intent is to provide margin to minimize the risk of generators tripping prematurely during an underfrequency event. Based on industry comments, the SDT has clarified this requirement by replacing the discrete points in the proposed standard with a continuous curve that provides a consistent 0.2 Hz margin between 0 and 60 seconds.		
Southern Company		We agree this change better coordinates with PRC-024.If coordination with PRC-024 is the ultimate goal, it seems a simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.).

Organization	Yes or No	Question 5 Comments:
Response: Thank you for your support. The SDT has adopted an approach that provides a constant offset of 0.2 Hz between 0 and 60 seconds.		
SERC UFLS Standards Drafting Team		We agree this change better coordinates with PRC-024.If coordination with PRC-024 is the ultimate goal, it seems a simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.)
Response: Thank you for your support. The SDT has adopted an approach that provides a constant offset of 0.2 Hz between 0 and 60 seconds.		
ReliabilityFirst Corporation	Yes	
System Protection & Control	Yes	
ReliabilityFirst	Yes	
AEP	Yes	
Ontario Power Generation	Yes	
We Energies	Yes	
NextEra Energy Resources, LLC	Yes	
Luminant Power	Yes	
City of Bedford	Yes	
US Army Corps of Engineers	Yes	
Central Lincoln	Yes	

Organization	Yes or No	Question 5 Comments:
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
City of Bedford	Yes	
US Army Corps of Engineers	Yes	
Central Lincoln	Yes	
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
Pepco Holdings, Inc – Affiliates	Yes	
Bonneville Power Administration	Yes	
Electric Market Policy	Yes	
FRCC Standards & Operations Departments	Yes	
Florida Municipal Power Agency and	Yes	

Organization	Yes or No	Question 5 Comments:
Select Members		
Cowlitz County PUD	Yes	

6. **In the first posting, the Characteristics of UFLS Regional Reliability Standards required that UFLS programs be designed to limit the potential for overexcitation (V/Hz) of power system equipment at all Bulk Electric System buses. Based on industry comments, the SDT has revised this requirement in the proposed continent-wide standard to apply only at generator buses and generator step-up transformer high-side buses associated with individual generating units greater than 20 MVA (gross nameplate rating) and generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) that are directly connected to the BES. The SDT believes this change better addresses the need to have UFLS programs designed to coordinate with protection that may trip generators during an underfrequency event. Do you agree with this change?**

Summary Consideration:

The SDT has considered industry input regarding the V/Hz performance characteristic. The majority of comments from the industry supported the changes made to this requirement in the second posting.

However, the team identified the need to make two clarifying changes to the requirement. Based on its own review of the requirement the SDT decided to remove any ambiguity as to whether modeling is required when all or only one threshold is met by combining R 6.4.1 and R6.4.2 with “OR” (now Part 3.3.1 of R3). Based on a comment the SDT also added a third threshold in Part 3.3.1 of R3 to clarify our intent to include wind generation, by adding “Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.” Thus, the applicability is limited to locations at which individual generating units greater than 20 MVA (gross nameplate rating) or generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) are directly connected to the BES or any facility consisting of one or more units that are connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT also has decided to modify Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.

The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from conservative simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard, the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.

Organization	Yes or No	Question 6 Comments:
Northeast Power Coordinating Council	No	We agree with the intent of the change to focus the concern on buses where V/Hz protection may trip generators rather than broadly applying to all BES buses. However, reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage or generating unit/plant nameplate MVA. We recommend that R6.4 apply to all generator buses and generator step-up (GSU) high-side buses similar to R7.1 and R7.2 applying to all generators that trip above 58.0 Hz or below 61.8 Hz.
Response: Thank you for your suggestion. The SDT has considered all industry input and has decided only to make clarifying modifications to the requirement. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity, which the team believes is sufficient accuracy for assessments of UFLS programs. The SDT also has decided to modify Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.		
Midwest ISO Stakeholders Standards Collaborators	No	Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit.This requirement should not be included with this standard because it cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation.The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document. During an under frequency event, generators should be working to pull voltages down anyway.Please see response to question 8 regarding overvoltages related to tripping load without tripping capacitors.
Response: It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT notes that the subject of the cited IEEE and ANSI standards is design and protection of generators and transformers. The proposed Requirement R6.4 (now Part 3.3 of Requirement R3) is a system performance requirement that is coordinated with these standards. If design verification studies demonstrate the potential for generator tripping, corrective measures must be applied to prevent further unnecessary outages or disturbances that would result from tripping the generator. **The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from conservative simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard, the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including**		

Organization	Yes or No	Question 6 Comments:
additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.		
MRO NERC Standards Review Subcommittee	No	Please provide the technical justification for this performance criteria. We are unaware of any UFLS event where V/Hz protection tripped a generator unit.This requirement should not be included with this standard because it cannot be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation.The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document.
Response: It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT notes that the subject of the cited IEEE and ANSI standards is design and protection of generators and transformers. The proposed Requirement R6.4 (now Part 3.3 of Requirement R3) is a system performance requirement that is coordinated with these standards. If design verification studies demonstrate the potential for generator tripping, corrective measures must be applied to prevent further unnecessary outages or disturbances that would result from tripping the generator. **The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard, the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.**		
IRC Standards Review Committee	No	We do not see the need to specify these criteria in the standard. Applicable requirements should be assigned to all generators that meet the compliance registry criteria.
Response: Thank you for your comment. The SDT agrees it would not be necessary to restate these criteria if we were assigning responsibility to the Generator Owners. However, in this case we are defining generator modeling requirements for the Planning Coordinators. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT is specifying these criteria rather than referencing the NERC Statement of Registration Criteria to ensure the technical requirements of this standard are independent of the NERC Statement of Compliance Registry.		
Hydro-Québec TransEnergie (HQT)	No	HQT agree with the intent of the change to focus the concern on buses where V/Hz protection may trip generators rather than broadly applying to all BES buses. However, reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping

Organization	Yes or No	Question 6 Comments:
		in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage or generating unit/plant nameplate MVA. We recommend that R6.4 apply to all generator buses and generator step-up (GSU) high-side buses similar to R7.1 and R7.2 applying to all generators that trip at particular frequency tresholds. See also our answer to Q8 in regards to frequency treshold.
Response: The SDT agrees that the impact of generator tripping on system frequency is independent of the interconnection voltage. However, the SDT believes it is not necessary or practical to assess the potential for tripping of every generator unit. The majority of comments from the industry supported the changes made to this requirement in the second posting. The SDT has considered all industry input and has decided only to make clarifying modifications to the requirement. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT also has decided to modify Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.		
Kansas City Power & Light	No	Do not agree with requirement R6.4 regarding the criteria for ensuring control voltage at the generator does not exceed 1.18 V/Hz for a duration longer than 2 seconds. The operating boundaries and control schemes at the generators are in place for the protection and reliable operation of the generator and should be modeled as they are and UFLS design should be modeled around the generator in the attempt to maintain generator connection to the grid.
Response: Thank you for your comment. The intent of this requirement is as the commenter suggests: to design the UFLS program around the generator in an attempt to maintain generator connection to the grid. However, instead of requiring the Planning Coordinators to model the over-excitation protection of each generator unit and generator step-up transformer the SDT has developed this performance characteristic based on the relevant IEEE standards governing equipment design and protection. The SDT believes this approach achieves the same objective without requiring extensive collection of data and modeling of over-excitation protection.		
NIPSCO	No	Since much of the future generation seems to be wind power- they should be included
Response: The SDT had intended to include wind generators and has modified Requirement R6.4 (now Part 3.3 of Requirement R3) to clarify this intent. **The SDT has modified Part 3.3 to include a reference to "Facilities consisting of one or more units connected to the bulk electric system at a common bus with total generation above 75 MVA gross nameplate rating."**		
Exelon	No	Don't agree with going into the generator over excitation equipment. This is an issue that is regional in nature

Organization	Yes or No	Question 6 Comments:
		and should be addressed at that level.
Response: Thank you for your comment. It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT believes that excitation equipment and generator design and protection is sufficiently uniform across North America that a continent-wide performance requirement is appropriate. **The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage.**		
American Transmission Company	No	Please provide the industry with the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a generator unit.This requirement should not be included with this standard because it cannot be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation.The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000)) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document.
Response: It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT notes that the subject of the cited IEEE and ANSI standards is design and protection of generators and transformers. The proposed Requirement R6.4 (now Part 3.3 of Requirement R3) is a system performance requirement that is coordinated with these standards. If design verification studies demonstrate the potential for generator tripping, corrective measures must be applied to prevent further unnecessary outages or disturbances that would result from tripping the generator. **The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.**		
American Transmission Company	No	Please provide the industry with the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a generator unit.This requirement should not be included with this standard because it cannot be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation.The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic

Organization	Yes or No	Question 6 Comments:
		mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000)) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document.
Response: It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT notes that the subject of the cited IEEE and ANSI standards is design and protection of generators and transformers. The proposed Requirement R6.4 (now Part 3.3 of Requirement R3) is a system performance requirement that is coordinated with these standards. If design verification studies demonstrate the potential for generator tripping, corrective measures must be applied to prevent further unnecessary outages or disturbances that would result from tripping the generator. **The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.**		
FirstEnergy Corp	No	The requirement has been devised to protect generators and step-up transformers from over-excitation based on traditional protection guidelines. However, other elements in the BES can also become over-excited. Dynamic simulations look at many quantities such as voltage and frequency but Volts/Frequency is not a common output that is reviewed. It is suggested that it would be better to require that bulk capacitors be tripped if system voltage exceeds equipment limits.
Response: The SDT initially considered a requirement to trip capacitors when voltage exceeds equipment limits. However, in developing the requirement the SDT realized that the concern with high voltage during an underfrequency event is the potential for generating units to trip by overexcitation protection, potentially exacerbating the underfrequency condition and leading to a blackout. As such, the SDT believes it is important to focus on the reliability impact on the BES and not how the impact should be addressed such as tripping bulk capacitors. While the SDT agrees that V/Hz is not an output quantity commonly reviewed, the capability does exist to monitor this quantity.		
Independent Electricity System Operator	No	The 20 MVA/unit and 75 MVA per generating plant/facility thresholds are the same as those presented in PRC-024, on which we expressed a disagreement. In an islanded situation, each generator's status is critical to ensuring frequency decline is successfully arrested based on the assumption that all on-line generators would not trip within specific frequency bounds unless prior approval has been sought and granted to allow tripping. Not limiting the potential for overexcitation (V/Hz) at the smaller generators/plants exposes the island to a great uncertainty on the amount of generation that can be relied upon to arrest frequency excursion.
Response: The SDT believes it is not necessary or practical to assess the potential for tripping of every generator unit. The majority of comments from the industry supported the changes made to this requirement in the second posting. However, the team identified the need to make two		

Organization	Yes or No	Question 6 Comments:
clarifying changes to the requirement. Based on its own review of the requirement the SDT decided to remove any ambiguity as to whether modeling is required when all or only one threshold is met by combining R 6.4.1 and R6.4.2 with "OR" (now Part 3.3.1 of R3). Based on a comment the SDT also added a third threshold in Part 3.3.1 of R3 to clarify our intent to include wind generation, by adding "Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating." Thus, the applicability is limited to locations at which individual generating units greater than 20 MVA (gross nameplate rating) or generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) are directly connected to the BES or any facility consisting of one or more units that are connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT also has decided to modify Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.		
Xcel Energy	No	No. Criteria in 6.4.1 and 6.4.2 looks like it is only measuring generators that are required to be registered. Yet, with increasing penetration of small generators (<20MVA, <75 MVA aggregate), we feel the scope is not large enough to consider a material impact on the BES by an aggregate of these small generators. (Same concern carries into R7)
Response: The majority of comments from the industry supported the changes made to this requirement in the second posting. However, the team identified the need to make two clarifying changes to the requirement. Based on its own review of the requirement the SDT decided to remove any ambiguity as to whether modeling is required when all or only one threshold is met by combining R 6.4.1 and R6.4.2 with "OR" (now Part 3.3.1 of R3). Based on a comment the SDT also added a third threshold in Part 3.3.1 of R3 to clarify our intent to include wind generation, by adding "Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating." Thus, the applicability is limited to locations at which individual generating units greater than 20 MVA (gross nameplate rating) or generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) are directly connected to the BES or any facility consisting of one or more units that are connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT also has decided to modify Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.		
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes this change creates a clear definition for equipment at generator buses and step-up transformer high-side buses for which the standard applies. However, the NERC UFLS SDT may want to consider adapting the definition of applicable generating units to conform to NERC's Compliance Registry Criteria (NERC Statement Compliance Registry Criteria Rev 5.0 (October 16, 2008) www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0[1].pdf for Generator Owner/Operator:- Individual generating unit greater than 20 MVA (gross nameplate rating) and is directly connected to the bulk power system;- Generating plant/facility greater than 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power

Organization	Yes or No	Question 6 Comments:
		system at a common bus with total generation above 75 MVA gross nameplate rating.This change would bring consistency to the definition of applicable generating units and would ensure that there is no confusion for wind farms and other generating plants/facilities.
Response: Thank you for your suggestion. The SDT has modified Requirement 6.4 (now Part 3.3 of Requirement R3) to include a reference to "Facilities consisting of one or more units connected to the bulk electric system at a common bus with total generation above 75 MVA gross nameplate rating."		
Colmac Clarion	Yes	Be aware that some small generators (>20 MVA but <75 MVA with 'extended' tielines may have difficulty meeting this requirement with some 'older' voltage regulators and stepup transformer arrangements.
Response: The SDT notes that this requirement is not applicable to Generator Owners. The requirement is applicable to Planning Coordinators to ensure that the UFLS program design within each region considers the potential for UFLS program operation to result in high voltage/low frequency conditions that may result in flux beyond design limits of generators and generator step-up transformers. This requirement ensures these impacts are considered during UFLS program design to minimize the likelihood that generation will trip by overexcitation protection which would exacerbate the underfrequency condition, potentially preventing recovery and stabilization of system frequency leading to a blackout.		
Alabama Municipal Electric Authority	Yes	The SDT should consider the potential discrepancy with the generator side and their desire to include automatic load reduction. I assume automatic load reduction would not take place at a generator bus.
Response: The SDT agrees with the commenter's assumption that automatic load reduction would not necessarily take place at a generator bus although this is not precluded by the standard.		
SPP System Protection and Control Working Group	Yes	Please confirm whether this requirement is applicable for generating stations/ plants connected to BES above 100 kV.
Response: This was the intent of the requirement in the second posting. The majority of comments from the industry supported the changes made to this requirement in the second posting. The SDT has decided only to make clarifying modifications to the requirement.		
PacifiCorp	Yes	PacifiCorp concurs with the decision of the SDT drafting team. V/Hz capability is generally associated with generating plants, not all buses within a system.
Response: Thank you for your support.		

Organization	Yes or No	Question 6 Comments:
Luminant Power	Yes	Luminant agrees with the direction of the UFLS SDT. Luminant further requests that the drafting team modify Requirement R6.4 to clarify that the per unit V/Hz limits modeled are 1.18 and 1.10 of Nominal transmission system voltage.
Response: Thank you for your support of the SDT direction on this requirement. However, the SDT has decided not to modify Requirement R3.3 to provide the V/Hz base. The SDT believes it is implicit that the V/Hz base is nominal system voltage divided by nominal system frequency, similar to voltage standards which typically refer to per unit voltage without explicitly stating the voltage base.		
Ameren	Yes	It is an improvement over the previous draft. However, there are still questions as to whether this requirement is needed. Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit. This requirement should not be included with this standard because it cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation.
Response: It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT notes that this performance characteristic is based on IEEE and ANSI standards applicable to design and protection of generators and transformers. The proposed Requirement R6.4 (now Part 3.3 of Requirement R3) is a system performance requirement that is coordinated with these standards. If design verification studies demonstrate the potential for generator tripping, corrective measures must be applied to prevent further unnecessary outages or disturbances that would result from tripping the generator. **The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.**		
ERCOT ISO	Yes	ERCOT ISO agrees with the change.
Response: Thank you for your support.		
Southern Company	Yes	No additional comment.
Pepco Holdings, Inc – Affiliates	Yes	
Bonneville Power	Yes	

Organization	Yes or No	Question 6 Comments:
Administration		
Electric Market Policy	Yes	
SERC UFLS Standards Drafting Team	Yes	
FRCC Standards & Operations Departments	Yes	
Florida Municipal Power Agency and Select Members	Yes	
Cowlitz County PUD	Yes	
City of Bedford	Yes	
US Army Corps of Engineers	Yes	
Central Lincoln	Yes	
Long island power Authority	Yes	
ReliabilityFirst Corporation	Yes	
System Protection & Control	Yes	
ReliabilityFirst	Yes	
AEP	Yes	

Organization	Yes or No	Question 6 Comments:
Ontario Power Generation	Yes	
We Energies	Yes	
NextEra Energy Resources, LLC		No comment.

7. If you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict in the comments section.

Summary Consideration: Most commenters did not feel that there were any conflicts involving the proposed standard. One commenter raised concerns with historic arrangements relative to tie-line standards, and another commenter raised a concern relative to potential timing inconsistency with Automatic Generation Control (AGC). The SDT does not believe either of these issues would impact the frequency response following a major disturbance that results in activation of a UFLS program. However, the SDT believes that to the extent that such existing arrangements are contrary to the reliability objective of the proposed standard, the Planning Coordinators should model any such contract requirements in their UFLS assessments.

Organization	Question 7 Comments:
TRE UFLS Standard Drafting Team	At this time, the TRE UFLS SDT does not believe this proposed standard conflicts with any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or other applicable standard of which the team members are aware.
Response: Thank you for your input.	
Colmac Clarion	Requirement differ from some current contract requirements that were 'inclusive' of existing tieline standards when written.
Response: The SDT is not aware of how existing tie-line standards would impact the frequency response following a major disturbance that results in activation of a UFLS program. Regardless, the SDT believes that grandfathering of existing arrangements that are contrary to the reliability objective of the proposed standard is unwise and may prove to be a hindrance to the successful implementation of this standard. The Planning Coordinators should model any such contract requirements in their UFLS assessments.	
Alabama Municipal Electric Authority	The SDT should re-look at the timing requirements (4 seconds)in this standard and the timing requirements (such as 6 seconds in the AGC requirement) of other standards.
Response: The SDT appreciates notification of the potential conflict. However, Automatic Generation Control (AGC) is not expected to provide a significant contribution to meeting the frequency recovery performance characteristic in the proposed standard. The performance characteristics in the proposed standard reflect the combined system response resulting from activation of the UFLS program as well as the frequency response of load and generation. As such, the SDT believes there is no conflict in establishing requirements for frequency recovery in a time frame before AGC will be activated.	
Xcel Energy	Not aware of any conflicts at this time.

Organization	Question 7 Comments:
Response: Thank you for your input.	
Southern Company	No Comments for Question #7.
ERCOT ISO	No comment
Electric Market Policy	None
Kansas City Power & Light	Not aware of any conflicts.
IRC Standards Review Comittee	None
Public Service Electric and Gas Company	Not aware of any conflicts.
SPP System Protection and Control Working Group	None at this time.
Exelon	Not aware of any conflicts at this time.
We Energies	We are not aware of any conflicts.
PacifiCorp	No comment
NextEra Energy Resources, LLC	No comment.
Luminant Power	None
Ameren	No
FirstEnergy Corp	We are not aware of any conflicts.
Independent Electricity System Operator	None

8. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard PRC-006-1.

Summary Consideration:

Comments on this question covered a wide range of topics. Several comments reiterated concerns stated in response to previous questions while some new concerns were raised.

Several commenters raised concern regarding assignment of applicability for developing the UFLS programs to the Planning Coordinators. Concerns included whether the Planning Coordinators are the correct entity (e.g. as opposed to the Balancing Authority), whether compliance could be assessed against a group of Planning Coordinators as opposed to individual entities, and whether the Planning Coordinators should be required to involve other entities or follow their respective regional standard development processes.

- The SDT reaffirms that the Planning Coordinator is the Functional Model entity with the wide-area view and technical skills required to design automatic UFLS programs and perform the UFLS assessments and noted that the Balancing Authority cannot take action in the time frame required to arrest frequency decline and recovery frequency to 59.3 Hz.
- The SDT has removed the group concept and requirements are now assigned to individual Planning Coordinators.
- The SDT noted that while the standard does not require that the Planning Coordinators involve other entities, the Planning Coordinator must work closely with other entities in performance of its role. The SDT has not included a requirement to involve the Distribution Providers and the Transmission Owners in the process because it would be difficult to measure “involvement” and because this involvement is not required to fulfill the reliability objective of the proposed standard. The SDT also notes that the standard should not be prescriptive as to the processes Planning Coordinators should use in designing UFLS programs. A regional standard that involves other entities in the UFLS program design may be considered.

Several commenters requested that the standard include specific requirements on how the UFLS programs should be designed and implemented, such as the amount of load to be shed, frequency thresholds, time delays, and how the UFLS programs will account for the impact of generators that trip above the underfrequency trip curve proposed in PRC-024.

- The SDT replied to these comments by noting that the proposed standard is focused on what reliability goals must be met. The proposed standard allows Planning Coordinators to decide on UFLS design parameters to meet these requirements. The SDT also noted that due to differences in physical system characteristics between regions, the design of the UFLS programs is best left to the Planning Coordinators in each region. Comments received during the two postings indicate industry support for this approach.

Several commenters requested justification for the performance requirements included in the standard.

- The SDT replied that the technical justification for these performance characteristics is to ensure that generation does not trip before the UFLS program has time to operate to arrest frequency decline and recover frequency within acceptable limits. The characteristics in the proposed standard have been coordinated with the trip limitations proposed by the Generator Verification SDT in PRC-024 and with equipment design and protection guides in IEEE standards.

Several commenters requested that the SDT address issues such as requiring generator owners to provide their relay setting data, minimum requirements on generator governing response, limitations on generator tripping for off-nominal frequency, maintenance and testing of UFLS relays.

- While the SDT agreed that many of the concerns raised by commenters are valid, they also are outside the scope of the SAR for this project. Where applicable, the SDT noted existing STDs that are addressing these issues. Specifically, the Generator Verification STD (Project 2007-09) is establishing limitations on generator tripping for off-nominal frequency and requirements for generators to report non-conforming protection settings in PRC-024, and the Protection System Maintenance & Testing SDT (Project 2007-17) is addressing maintenance and testing for all relay types in PRC-005.

Several commenters raised concerns and provided recommendations on requirements involving procedures for coordination with other regions and criteria for selecting islands.

- In response to a variety of comments the SDT deleted requirement R4 and combined other requirements to simplify the requirements for inter-area coordination and criteria for selecting islands to be used as a basis for designing a UFLS program. These revised requirements are contained in Requirements R2 for selecting islands and R5 for inter-area coordination.

Several entities recommended that the proposed standard exclude small entities from requirements to implement the UFLS program designed by the group of Planning Coordinators in their region.

- The SDT indicated this is an aspect of the UFLS program design assigned to the group of Planning Coordinators. The SDT further noted that the group of Planning Coordinators can provide in the UFLS program such allowances as long as compliance with the performance characteristics in requirement R3 (requirement R6 in previous posting) is achieved.

One entity identified potential conflicts between approved reliability standard EOP-003, Load Shedding Plans, and the proposed standard.

The SDT agrees that PRC-006-1 and EOP-003-1 should not include duplicative or contradictory requirements. The SDT has requested and received Standards Committee approval to propose a supplement to its scope to include making conforming changes to EOP-003-1. The Supplemental SAR and proposed revisions to EOP-003-1 have been included with the third posting of PRC-006-1. One entity indicated that the requirement for post-event analysis presently contained in PRC-009 has not been included in the proposed standard, leaving a gap in analysis of events. The entity suggested this must be covered in a reliability standard and should not be referred to ERO Rules of Procedure.

- Upon further consideration, the SDT agreed with the comment and added a requirement to include an assessment of the performance of UFLS equipment and the UFLS program effectiveness (new Requirement R11) within one year of an actuation of UFLS resulting in a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program.

Several commenters requested that the database should include all data required to perform a UFLS Assessment.

- The SDT notes that the database is intended to document the load tripping implemented by Distribution Providers and Transmission Owners to meet Requirement R9. In fulfilling the Planning Coordinator function, the groups of Planning Coordinators have the ability to obtain protection settings they need to model to comply with R4 and R11. Planning Coordinators and Transmission Planners routinely obtain similar data to perform planning studies required by the Transmission Planning (TPL) standards.

Several entities requested that the drafting team propose definitions for several terms to be included in the NERC Glossary, including the terms region, island, underfrequency load shedding (UFLS), and annually.

- The SDT provided explanations of how these terms are used in the proposed standard, and noted that the terms region, island, and UFLS are understood terms used within the industry and the word annually is used as defined in a collegiate dictionary. The team did; however, clarified in the standard that “region” refers to a Regional Entity footprint.

Organization	Question 8 Comments:
TRE UFLS Standard Drafting Team	The TRE UFLS SDT appreciates the opportunity to provide these comments and commends the NERC UFLS SDT for its efforts.
Response: Thank you for your support.	
Bonneville Power Administration	The Applicability should be Planning Coordinators and Balancing Authorities. BPA suggests that everywhere it currently states Planning Coordinator that it be changed to ?Planning Coordinator/Balancing Authority?. **Response: The SDT believes the Planning Coordinator is the Functional Model entity with the wide-area view and technical skills required to design UFLS programs and perform the UFLS assessments. The Balancing Authority cannot take action in the time frame required to arrest frequency decline and recover frequency to 59.3 Hz within 60 seconds.** R3. - This needs to say why they are selecting portions of the BES that may form islands. The reason would be "that may form islands to simulate frequency performance and design the UFLS schemes." **Response: The reason is given in R5 (now R2), “Each group of Planning Coordinators shall identify an island(s) as a**

Organization	Question 8 Comments:
	basis for designing a UFLS program." R5. Second bullet - This should include both "relay scheme or special protection system." **Response: The SDT agrees with this comment and has revised the requirement (now R2, Part 2.2) accordingly.** Related to R9. - Each Generator Owner also needs to provide data for their under frequency trip settings, if they are within the band specified, 58.0 Hz to 61.8 Hz, since they also need to be considered in the simulations. **Response: Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. Adding such a requirement in PRC-006-1 will create a redundant data requirement already contained in PRC-024-1.**
Northeast Power Coordinating Council	NPCC has previously commented that the objective to control frequency overshoot cannot be met through UFLS program design alone in the absence of adequate generating unit governing response. Our immediate concern has been addressed by increasing the maximum overshoot limit to 61.8 Hz and we support this modification to the performance requirements. However, we expect this concern will resurface if standards requiring minimum frequency response are not implemented and further declines in system frequency response are observed. NPCC recommends that NERC develop standards for unit governing response that are consistent with and support the reliability objectives of standards PRC-006 (UFLS) and PRC-024 (Generator Performance). **Response: The SDT agrees, though this is outside the scope of its activities. We suggest you submit this suggestion using a *Standards Suggestions and Comments Form* – the form can be downloaded from the Standards Resources Web Page, or using the following link:** **http://www.nerc.com/files/Standards_Input_Form_Final_2008June30.doc** NPCC also notes that it may not be possible for the Planning Coordinators to design a reliable UFLS program that will arrest and recover declining frequency if an excessive number of generators are exempted from meeting the underfrequency performance requirements in PRC-024. **Response: The SDT agrees, though this needs to be addressed by the Project 2007-09 (Generator Verification) PRC-024 SDT.** Hydro-Quebec TransEnergie has technical parameters that differ from those specified in Requirements R6 and R7. A Variance will be needed to address those specific concerns. **Response: A variance for the Québec Interconnection is included in the third posting of the standard.**
Southern Company	--- R8: It is problematic for a loosely organized group of Planning Coordinators to create and maintain a database. There are

Organization	Question 8 Comments:
	several practical and compliance issues with this. This should be assigned to an entity with clear responsibilities and pro
Response: This requirement (now R6) has been reassigned to individual Planning Coordinators. Annual collection of data is desirable in case events need to be analyzed. A database can be any collection or compilation of data the Planning Coordinator chooses.	
ERCOT ISO	Comment 1- May need to consider defining the meaning of region (Region) in the NERC Glossary so it is clear for the responsible entities for this standard. **Response: The SDT intended "region" to relate to the traditional sense of the defined boundaries of a Regional Reliability Organization (RRO) and its successor the Regional Entity. The SDT feels that the concept of a "region" is generally understood throughout the industry and does not believe that a unique definition is required. The term "Regional Entity footprint" replaces "region" in the third draft.** Comment 2 Will it be necessary for ERCOT ISO to have a procedure for coordinating with groups of Planning Coordinators, since we are essentially a group of one? Maybe language could be added to the standard to clarify for this situation. **Response: The SDT modified the standard to no longer require a procedure. The requirements are also now assigned to individual Planning Coordinators rather than groups.**Comment 3 - It would be appropriate for the load referenced in the imbalance calculation in requirement R6 to include system (island) losses. The standard should be clearer. **Response: The SDT intentionally excluded island losses from the imbalance definition. The losses within an island are difficult to measure because the losses in the steady-state pre-event condition will change upon formation of the island. The SDT notes that excluding losses results in a slightly more conservative assessment because more generation would have to be online for a given imbalance if losses are included in the equation. In most cases the losses are on the order of 1 to 3 percent; thus while excluding losses is conservative, it is not overly conservative.**
Midwest ISO Stakeholders Standards Collaborators	R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria. **Response: The SDT recognizes the difficulties that could be encountered in identifying islands. Nevertheless, there may be portions of a system that obviously have a higher likelihood of islanding as compared to others. How extensive an analysis to identify islands needs to be is a judgment that cannot be written into a standard and must be left to the discretion of the Planning Coordinators involved. The standard only requires that criteria for identifying islands be developed, documented and applied.** R2 We would suggest removing the word "consistent" because the program can not be applied consistently across the MRO

Organization	Question 8 Comments:
	Region. The Canadian systems need to shed more load than the US portion of MRO. We need to focus on coordination issues between geographic areas, not on consistent application across a NERC region. Perhaps what was intended is to state that load shedding should be applied uniformily across any island footprint. **Response: The SDT agrees with the comment and has revised requirement R3 (that reflects merging of Requirement R2 into R5) with removal of the word, "consistent."** R4 - Revise text so that the "agreement" between all entities is well documented through several examples: meeting minutes, a formal agreement to work together, results of common drills, examples of coordination of UFLS models, etc.) We would propose that the assessment for non compliance would be located in the formal agreement to work together since all parties should understand the risk or consequences of the group effort. **Response: Requirement R4 has been deleted.** These standards do not appear to consider or address if capacitors should be automatically tripped during UFLS to avoid overvoltage conditions. Do other standards address this or does this draft standard need to be modified? **Response: The SDT feels that R6.4 (Part 3.3 of requirement R3 in the third draft) appropriately addresses overvoltage conditions without specifying how the volts per hertz requirement should be met. The SDT believes that requiring capacitor tripping in the standard would address "how" to meet the requirement rather than stating "what" reliability objective is being addressed.**
SERC UFLS Standards Drafting Team	R8: It is problematic for a loosely organized group of Planning Coordinators to create and maintain a database. There are several practical and compliance issues with this. This should be assigned to an entity with clear responsibilities and processes to accomplish the task. Additionally, annually and database is unnecessarily restrictive given the study is only required on a 5 year basis and in light of existing data collection processes. Recommend revision R8 as follows: shall compile/assemble information provided by their Transmission Owners and Distribution Providers for use in UFLS assessments and event analyses. Databases should add value and not create extra work that does not directly contribute to the completion of the study.--- **Response: This requirement (now R6) has been reassigned to individual Planning Coordinators. Annual collection of data is desirable in case events need to be analyzed. A database can be any collection or compilation of data the Planning Coordinator chooses.** R7.1 and 7.2 could have the effect of shifting the generators burden of staying on line to the load customer who must be shed to account for the generators less-than-expected frequency performance. The generators must be modeled because that is the way they perform, but an exception for frequency support must be difficult for a generator to obtain.--- **Response: The SDT agrees, though, exceptions for frequency support provided by the generators need to be addressed by the Project 2007-09 (Generator Verification) PRC-024 SDT. The current draft of PRC-024 does require documentation and response to technical review by other entities for any non-conforming trip settings.**

Organization	Question 8 Comments:
	R10 should say ?shall implement the UFLS program rather than shall provide load tripping in accordance with the UFLS program because the phrase ?provide load tripping could be confusing.--- **Response: The SDT deliberated on the words "shall implement" and while we agree with the intent we feel that "shall provide load tripping" is more explicit.** R1 through R8: The concept of PC's joining a group to design a UFLS scheme is flawed. Compliance should never be assessed on a group basis. Each PC (or TP) must be allowed to demonstrate compliance to the standard independently so compliant PCs/TPs are not penalized along with the non-compliant one(s). The standard should be applicable to individual PC's/TPs to design their UFLS scheme to meet the other requirements. The performance characteristics insure that the schemes from different PC's/TPs will coordinate. However, if a group approach is mandated, then sub-regional groups must be allowed in lieu of regional groups.--- **Response: Thank you for your comment. The group of Planning Coordinators concept has been removed and replaced by individual Planning Coordinators.** R4 is an unnecessary complication, and should be deleted. A procedure for identifying islands between Regions is not necessary. What if there are no credible islands between Regions? R5 ensures that when credible islands between Regions are identified that all affected entities jointly study UFLS scheme effectiveness within the island.--- **Response: The SDT agrees and Requirement R4 has been deleted.** R6: Does this requirement say that performance requirements must be met only at a 25% imbalance? Or is it requiring performance requirements to be met at lower imbalances too? If yes, we recommend performing both a 25% and a 15% imbalance test to add clarification.--- **Response: The requirement indicates that the performance characteristics apply to any percentage between 0 and 25. A number of imbalances need to be simulated to demonstrate that the performance characteristics can be met through the range**. R10: Does each DP have to specifically meet the UFLS scheme? For example, if the UFLS scheme is for 30% load in 3 steps of 10% each, some small DP's may not be able to achieve that fine a resolution. Some allowance should be made for aggregating DP's to meet the overall scheme. This allowance should be achieved by making the TO responsible for implementing the UFLS scheme. The TO has a wider area of control and responsibility and is therefore in a better position to coordinate the implementation.--- **Response: The group of Planning Coordinators can provide in the UFLS program any such allowance as long as compliance with the performance characteristics in requirement R3 (requirement R6 in previous posting) is achieved.** Unless there is a high bar in PRC-024 to obtain an exception, this passes the responsibility for generators to support frequency on to the loads (to support frequency by shedding). To compensate this standard needs a requirement for generators which do

Organization	Question 8 Comments:
	not coordinate with the R6 requirements to arrange for load to be shed to make up for their generator tripping.--- **Response: Per R5 of the first draft of PRC-024-01, Generator Owners will need to document, subject to peer review, any generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1. Since this standard does not apply to Generator Owners, the preceding comment should be directed to Project 2007-09 which covers PRC-024-01.** **The proposed standard allows Planning Coordinators in each region to determine what measures will be included in the program design to account for the impact of generators with trip settings that trip above the curve in PRC-024.** R7.1: This should not require the modeling trip settings of all generators that trip at or above 58.0 Hz. Since most generators have trip settings for reduced frequency that holds for long periods (e.g. 30 minutes), this would require modeling trip settings of almost all generators. It should only require the modeling trip settings of generators that would trip within the performance envelope defined by R6.1 and R6.2.--- R7.2: This should not require the modeling trip settings of all generators that trip at or below 61.8 Hz. Since most generators have trip settings for higher frequency that holds for long periods (e.g. 30 minutes), this would require modeling trip settings of almost all generators. It should only require the modeling trip settings of generators that would trip within the performance envelope defined by R6.3.--- **Response: The SDT agrees and has modified Parts 4.1 through 4.6 of requirement R4 (previously R7.1 and R7.2) to require the modeling of generators with protection settings above and below the frequency-time curves rather than focusing on tripping above or below a specific frequency threshold.** It is not clear if the standard requires one specific UFLS scheme for the entire Region. One scheme for the Region should not be mandated. Flexibility should be allowed for different schemes within the Region as long as each scheme meets the performance requirements. **Response: The SDT has addressed this concern by eliminating the word "consistent."**
FRCC Standards & Operations Departments	We appreciate the Drafting Teams efforts on this very difficult standard and would offer the following suggested clarifications:R8. Each group of Planning Coordinators shall create and annually maintain a UFLS database containing relay information provided by their Transmission Owners and Distribution Providers for use in UFLS assessments and event analyses. Suggest rewording R8 as follow: R8. Each group of Planning Coordinators shall maintain a UFLS database which identifies the participating Planning Coordinators, contributing entities and contains information (as defined in R9) provided by their Transmission Owners, Distribution Providers and Load Serving Entities for use in UFLS assessments and event analyses. **Response: The SDT has revised Requirement R8 (now R6) in response to a number of different suggestions from commenters. However, the SDT has not included requirements to identify the participating Planning Coordinators or for Load Serving Entities (LSEs) to provide data. This requirement (now R6) has been reassigned to individual Planning Coordinators. The equipment owners (Distribution Providers and Transmission Owners) are the entities with the data**

Organization	Question 8 Comments:
	required by Planning Coordinators, so there is no reason to include LSEs in this requirement. Suggest adding Load Serving Entities to R9. **Response: The equipment owners (Distribution Providers and Transmission Owners) are the entities with the data required by Planning Coordinators, so there is no reason to include LSEs in this requirement.** R10. Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates. Suggest rewording R10 as follows: Each Transmission Owner, Distribution Provider and Load Serving Entity shall provide forecast load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates. **Response: The SDT has not added the word "forecast" to the requirement. Because automatic UFLS programs must be planned in advance, the use of forecasted load is considered a given.**
MRO NERC Standards Review Subcommittee	R1 - Reword the requirement to state the Planning Coordinators within a region shall have an agreement with all the Planning Coordinators rather than creating a new group. (For example similar to agreement requirements between BAs in EOP-001, between GOs and transmission entites in NUC-001, and RCs to form an agreement in IRO-001 R7.) Proposed wording for R1: "Planning Coordinators shall have agreements with all Planning Coordinators in the region, that shall, at a minimum, contain provisions for cover fulfillment of the subsequent UFLS requirements in the standard."This agreement would clarify how "group" responsibilites for compliance and penalties would be assigned to its member entities. For example, would all Planning Coordinators be non-compliant, if one or more members of the group is non-compliant or if a group could not come to consensus on elements needed to fullfill a requirement? Would the financial penalty be shared among the group or would each member be assessed separate penalties? **Response: The group of Planning Coordinators concept has been removed and replaced with individual Planning Coordinator applicability.** R2 We suggest the following revised wording, "shall design a load shedding program or multiple load shedding programs so that all areas of the region are covered." In the MRO, the Canadian portions of the system need to shed more load than the U.S. portion of the system. There needs to be coordination within each potential island, but not necessarily consistent across each, entire NERC region. Perhaps what was intended is to state that load shedding should be applied uniformly across an island footprint. **Response: The SDT has addressed this concern by eliminating the word "consistent."** R4 - Revise text so that the "agreement" between all entities is well documented through several examples: meeting minutes, a formal agreement to work together, results of common drills, examples of coordination of UFLS models, etc.) We would propose that the assessment for non-compliance would be located in the formal agreement to work together since all parties should understand the risk or consequences of the group effort.

Organization	Question 8 Comments:
	Response: Requirement R4 has been removed. R6.1 To match the design emphasis that is included in R6.2 and R6.3, we suggest . . . no less that 58.0 Hz per simulated event. **Response: The SDT has revised these requirements to refer to frequency-time curves rather than specific thresholds and time durations. The SDT believes that the revised requirements (now Parts 4.1 and 4.2 of R4) address the commenters' concern.** R8 - Since the interpretation of "annually" can vary widely, we suggest this rewording, "each calendar year and within 15 months of the last update". **Response: Since "annually" is not defined a NERC term, it has the meaning "occurring or happening every year or once a year." as found in a collegiate dictionary. The SDT believes the reliability objective of this requirement is met without specifying details of when during the year the requirement is fulfilled.** R9 If the inclusion of Transmission Owner is determined to be redundant, reword to, Each Distribution Provider shall provide. . ., as noted in response to Q1.b. **Response: The SDT has decided to retain both the Distribution Provider and the Transmission Owner in the applicability for this requirement. The drafting team provided the rationale for keeping Transmission Owner in response to comments to Question 1B.** R10 If the inclusion of Transmission Owner is determined to be redundant, reword to, Each Distribution Provider shall provide . . ., as noted in repsonse to Q1.b. **Response: The SDT has decided to retain both the Distribution Provider and the Transmission Owner in the applicability for this requirement. The drafting team provided the rationale for keeping Transmission Owner in response to comments to Question 1B.** add R11 - Since reactive power device overvoltage or underfrequency protection may be included to the UFLS program assessment, we suggest adding the Requirement, "R11. Each Distribution Provider and Transmission Owner shall provide its reactive power device overvoltage or underfrequency protection information in the format and according to the schedule specified by the applicable Planning Coordinator." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section.] **Response: The database is intended to document the load tripping implemented by Distribution Providers and Transmission Owners to meet Requirement R9. In fulfilling the Planning Coordinator function, Planning Coordinators have the ability to obtain protection settings they need to model to comply with R4 and R11. Planning Coordinators and Transmission Planners routinely obtain similar data to perform planning studies required by the Transmission Planning (TPL) standards.** add R12 - Since reactive power device overvoltage or underfrequency protection should be included in the UFLS program design

Organization	Question 8 Comments:
	for a specific island, we suggest adding the Requirement, "R12. Each Distribution Provider and Transmission Owner shall provide reactive power device tripping in accordance with the UFLS program designed by the applicable Planning Coordinator for each region in which they operate." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section.] **Response: The SDT has added a new requirement R10 that requires Transmission Owners to provide automatic switching of Elements in accordance with the UFLS program design. The SDT believes this general requirement is more appropriate to include both energizing and de-energizing reactive devices or any other system Elements when included by the Planning Coordinators as part of the UFLS program design.** add R13 - Since generator off nominal frequency protection information may be included to the UFLS program assessment, we suggest adding the Requirement, "R13. Each Generator Owner shall provide its off nominal frequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators." **Response: The SDT does not believe this requirement is necessary. Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. Adding such a requirement in PRC-006-1 will create a redundant data requirement already contained in PRC-024-1.** add R14 - Since the coordination of generator off nominal frequency protection should be included to the UFLS program design for a specific island, we suggest adding this Requirement "R14. Each Generator Owner shall have evidence that they provided any coordination that is required by the applicable regional group of Planning Coordinators to meet UFLS program specifications." **Response: The SDT does not believe this requirement is necessary. Coordination between generator off-nominal frequency tripping and UFLS is already being achieved between this standard and draft PRC-024-1.** It is not clear if the standard requires one specific UFLS scheme for the entire Region. One scheme for the Region should not be mandated.Flexibility should be allowed for different schemes within the Region as long as each scheme meets the performance characteristics. **Response: The SDT has addressed this concern by eliminating the word “consistent.”** Below is a list of technical requirements or issues the MRO NSRS would like the UFLS DT to consider for either a reference document or for regional variences. A. Limited Number of Island Loads - What allowance should made for Distribution Providers with a limited number of loads in a designated island? **Response: Planning Coordinators can provide in the UFLS program any such allowance as long as compliance with the performance characteristics in requirement R3 (requirement R6 in previous posting) is achieved.**

Organization	Question 8 Comments:
	B. 58 Hz Limit - Consideration should be given to circumstances in some islands where a lower frequency limit would allow better UFLS program performance. For instance the the Canadian example mentioned above. **Response: This may be addressed through a variance as outlined in the NERC Rules of Procedure. The SDT encourages the requestor of a variance to submit its request with a SAR which addresses the variance in detail.** C. Coordination with the Proposed PRC-024 Standard - Consideration should be given for proper coordination for of this standard (UFLS) with the PRC-024 standard especially with reguard to off-nominal frequency settings for generation. **Response: The SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team (GV SDT) by providing the underfrequency performance curve to ensure that the performance characteristics do not conflict with the generator off nominal frequency capability curve. The SDT will continue to coordinate with the GV SDT.** D. Reference Document - We think it would be valuable to develop a companion reference document that may contain the following expectations and intentions: - The intent of this standard is to ensure UFLS programs are effective, and to the extent possible, that potential problems have been addressed in the design phase. - This standard should achieve an appropriate level of reliability and not just the least common denominator. An evaluation should be made to determine if the minimum load shedding requirement is sufficient and appropriate for a given geographic region. Although no geographic region (potential island) is obligated to exceed the minimum load shedding requirement, load shedding beyond the minumum requirement is encouraged when there is an identified advantage of doing so. - Overall coordination issues are easier to satisfy for programs that shed the minimum amount of load. Such programs will be better behaved over the smaller range of overloads, but the system will collapse if loss of generation (or import) exceeds the amount of load shed. Larger, more aggressive load shedding programs will provide a larger safety net at the expense of wider voltage and frequency deviations, and generation in those areas will need to accept more off-nominal frequency exposure to achieve coordination with load shedding. - UFLS analysis has to deal with considerable uncertainty in a multitude of variables. It is assumed that conflicting performance requirements and tradeoffs will be documented and resolved through application of engineering judgment. - This standard acknowledges that performance measures such as frequency and voltage deviation are subjective. Both voltage and frequency are influenced by hard-to-quantify factors that vary in real time, such as load damping, the net governor response, and inertia of spinning on-line units. Such performance measures can only be applied in consistent fashion to a tightly defined set of qualifying assumptions. - This standard acknowledges that UFLS is basically a last ditch effort to prevent system collapse and that it has limits. It is not possible to achieve desired performance for all of the unlikely events that may occur in real life. - Performance characteristics given in this standard should be treated as design targets or design guidelines. Studies run to

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	develop UFLS programs may indicate different design criteria is appropriate as part of the overall compromise that has to be struck between performance and the level of load shedding coverage that is desired. - There is no perfect tool for studying UFLS, and this standard is not meant to prescribe any particular engineering approach to system analysis and review of UFLS performance. For example, the equivalent inertia method allows for sensitivity analysis and broader insight into the frequency decay dynamics. Likewise, the full transient stability case is more useful for simulating actual disturbance conditions including voltage transients. **Response: The SDT agrees with many of the guiding principles described above, but does not agree that a reference document is necessary. The SDT notes that UFLS programs have existed for forty years and believes that the Planning Coordinators have adequate expertise to understand the requirements of the proposed standard.** **The SDT also disagrees that standard requirements should be viewed as design targets or guidelines. The SDT assumes that reasonable assumptions pertaining to load damping and governor response will be made in the UFLS assessments, and that inertia will be representative of the systems studied.** **The SDT notes that a UFLS program capable of shedding more than 25 percent of a system's load would only need to comply with the performance characteristics up to a 25 percent load-generation imbalance. Beyond a 25 percent load-generation imbalance, a UFLS program would not be subject to any NERC imposed requirements, although the Planning Coordinators within a region could devise other performance characteristics that would apply under load-generation imbalance scenarios greater than 25 percent. The SDT understands the concern over larger sub-regional UFLS programs. The SDT recognizes that Planning Coordinators in a region with a 60 percent capable UFLS program, for example, may have trouble complying with the performance characteristics even under a 25 percent load-generation imbalance scenario. The SDT is not convinced that it would be impossible to comply, but can see that it could be more difficult. Assessments that demonstrate the reliability objective of PRC-006 can be met without meeting the performance characteristics in Requirement R6 could be used to support a request for a regional variance.** **While the standard does not prescribe any particular engineering approach to system analysis, the SDT believes that dynamic simulations are the only appropriate means of assessing compliance to the performance characteristics in R3 (previously R6).**
Kansas City Power & Light	1. What is the engineering basis for any of the boundary and threshold criteria established by requirement 6 and its sub-requirements? These prescribed requirements may not fit with already established UFLS systems and to justify the expense of changes there should be a sound engineering basis for doing so.2. **Response: The technical justification for these performance characteristics is to ensure that generation does not trip before the UFLS program has time to operate to arrest frequency decline and recover frequency within acceptable limits. The characteristics in the proposed standard have been coordinated with the trip limitations proposed by the Generator Verification SDT in PRC-024 and with equipment design and protection guides in several IEEE standards. The SDT does not anticipate that existing UFLS programs will need to be redesigned to meet this requirement (now**

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	Requirement R3) for load-generation imbalances up to 25 percent. R9 requires Transmission Owners and Distribution Providers according to a schedule and format specified by the Planning Coordinator, but does not require Generator Owners to provide generator protection information. Recommend the SDT consider the inclusion of generator information in the appropriate places in these requirements. **Response: The SDT does not believe this requirement is necessary. Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. Adding such a requirement in PRC-006-1 will create a redundant data requirement already contained in PRC-024-1.**
IRC Standards Review Comittee	R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria. **Response: The SDT recognizes the difficulties that could be encountered in identifying islands. Nevertheless, there may be portions of a system that obviously have a higher likelihood of islanding as compared to others. How extensive an analysis to identify islands needs to be is a judgment that cannot be written into a standard and must be left to the discretion of the Planning Coordinators involved. The standard only requires that criteria for identifying islands be developed, documented and applied.** The fourth bullet in R5 is unnecessary since (all assets) (assets in Island 1) (assets in island 2) - .. = (remaining assets not in any other island)Alternatively, the SDT may want to consider a requirement to perform one or more ad hoc stress tests that can be used to define islanding conditions. If PC passes the stress test, than there is no obligation to define an island within the PC; if the PC fails the stress test, than the PC must use the results as a partial (or complete) basis for defining one or more PC islands **Response: The SDT believes that Part 2.3 of Requirement R2 (fourth bullet of old requirement R5) is necessary to ensure regional coordination, and that if islands are not identified through system studies, historical events or planned islands, then the region as a whole is studied as an island in the assessment. The SDT notes that Planning Coordinators could include conducting a stress test to define islanding conditions as part of their criteria to identify islands to meet Requirement R1 (old requirement R3).**
Cowlitz County PUD	Past experience has proved from efforts to comply with other data request mandated standards a disconnect on what specific data needs to be on hand for proper modeling. Keep in mind that the DP usually does not have the expertise, including many TOs, on what data will be needed. I would suggest there be a requirement that the PC not only develop the data set required,

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	but actively (not passively) communicate to its DPs and TOs what is required. Simply expecting entities to stumble around in a web site and find the requirements complicates compliance efforts. Please note that I am not an expert in UFLS schemes and offer my limited knowledge as a compliance and distribution engineer. Thank you for the opportunity to join in this venue.
Response: The SDT understands the concern and believes that requiring that the data be provided according to the format and schedule defined by the Planning Coordinators in Requirement R8 establishes the "what" is needed to properly conduct UFLS assessments and events analyses.	
City of Bedford	Distribution providers with fewer than 10,000 meter should be exempted for the UFLS program because their ability to effect the stability of the electrical grid is minimal and the cost of installing and maintaining the system would excessive.
Response: Planning Coordinators can provide in the UFLS program such an allowance as long as compliance with the performance characteristics in requirement R3 (requirement R6 in previous posting) is achieved.	
Alabama Municipal Electric Authority	In requirement 10, "R10. Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates.", it requires the Distribution Provider to provide load tripping. This seems to imply that the Distribution Provider would not be able to satisfy this obligation in aggregate from its Balancing Authority or Transmission Operator through its power supply contracts. The requiement to provide load tripping is especially troublesome for small entities that have only one feeder supplying the load of its end use customers. Additionally a small entity that is registered as a Distribution Provider that has less than 100 MWs of load will provide little help in affecting the frequency of the BES. The SDT should consider a class of Distribution Providers and not all Distribution Providers.
Response: Planning Coordinators can provide in the UFLS program such an allowance as long as compliance with the performance characteristics in requirement R3 (requirement R6 in previous posting) is achieved.	
NIPSCO	Any standard neededs to be very general- should include the effect of load on frequency;Define what amount of load they require to trip; Include rate of frequency change protection.Only require planned load tripping; Actual load is much more difficult to predict on lower voltagecircuits.
Response: The SDT tried to be specific on what needs to be accomplished for reliability without being prescriptive on how to meet what is required. The details of the UFLS program such as amount of load tripping are to be defined by Planning Coordinators.	
SPP System Protection and Control Working Group	None at this time.
Long island power	Consider rewoeding R10 to better limit the Compliance aspect for the DP to implement setting UFLS relays based on the

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Authority	forecasted loads projected for the peak period. Suggest this R10 - The DP once per calendar year shall review the forecasted loads it is serving and provide for UFLS in accordance with the UFLS program designed by the group of planning Coordinators for each region in which it operates.
Response: The SDT has not added the word "forecast" to the Requirement. Because automatic UFLS programs must be planned in advance, the use of forecasted load is considered a given. Details as to whether peak load or other load conditions are used as the basis of the program design is left to Planning Coordinators to determine.	
Exelon	There is a concern with high frequency requirements because they are not clear as to what should occur or how it should be mitigated. If island frequency is greater then 60.7 HZ for more than 30 seconds what type of action needs to occur? What is the technical justification for these levels? **Response: The technical justification for this requirement is to ensure that generation does not trip as a result of frequency overshoot following operation of the UFLS program. The overfrequency characteristic in the proposed standard has been coordinated with the overfrequency trip limitations proposed by the Generator Verification SDT in PRC-024. If island frequency is greater than 60.7 Hz for more than 30 seconds the Planning Coordinator should modify the UFLS program design to reduce the level of overshoot, such as by increasing the number of UFLS stages and decreasing the amount of load shed at each stage.** In the previous Characteristics document the high voltage levels were different than the levels in this draft standard. **Response: The SDT believes the commenter is referring to the overfrequency limits having changed. The SDT raised the limits based on industry input during the first posting. The limits have been raised to take advantage of generator capability while maintaining coordination with the generator trip limits proposed in PRC-024. Based on industry input in the second posting, the overfrequency limits have been modified again to convert the discrete points to a curve.** Due to the inherent difficulty in accurately postulating load and generation islands, establishing frequency limits for such islands is even more difficult. There should be a criteria as to how the studies are done (including islanding criteria and size) if there are going to be bounds placed on the frequency result of the simulation. **Response: The SDT has defined the maximum imbalance between load and generation for which the performance requirements must be achieved. The SDT believes that for imbalances up to 25 percent it is possible to meet the performance characteristics for any island that may form. Details such as the process by which islands are identified are left to Planning Coordinators. The SDT believes that due to differences in physical system characteristics between regions, issues such as how studies are done are best left to the Planning Coordinators in each region. Comments received during the two postings indicate industry support for this approach.** If the timing components (4,10,20 seconds) are removed, then regions should establish minimum generator tripping standards for load shedding. Unit tripping should be a balance between limiting cumulative damage while at the same time coordinating with

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	load shedding levels in order to arrest frequency decline. **Response: The SDT agrees that unit tripping limits should achieve a balance between limiting cumulative damage while at the same time coordinating with load shedding levels in order to arrest frequency decline. This balance is being accomplished on a continent-wide basis by this SDT's coordinating the drafting with the Generator Verification SDT rather than a regional basis as suggested by the commenter.** Disagree with requirement 5. Criteria for island formation and the resulting requirements for mitigation should be included in a standard where affected parties may participate through the open and fair NERC process. There should not be some unspecified criteria left up to various entities with no oversight or standaridized development process. It would be very difficult if not impossible to determine how islands will be formed and where load will remain intact. **Response: The SDT believes the standard should define what is required of the Planning Coordinators without being prescriptive as to how the requirements should be fulfilled. The SDT also notes that due to differences in physical system characteristics between regions, the process for identifying islands is best left to the Planning Coordinators in each region rather than attempting to put them into a continent-wide standard. Comments received during the two postings indicate industry support for this approach. A regional standard may be considered if the continent-wide standard is not specific enough.**
ReliabilityFirst Corporation	SDT has to develop a mechanism to make sure all the loads are accounted for.
Response: The SDT has modified the applicability to include both Distribution Providers and Transmission Owners as UFLS entities. It will be up to the Planning Coordinators as to how this objective will be achieved so that the performance characteristics may be satisfied.	
Arkansas Electric Cooperative Corporation	R7.2 the wording "... trip at or below 61.8 Hz" implies that any generator with a trip setting below 61.8 must be modeled. If a generator has an UNDER-frequency trip setting below 58 Hz then it falls into this catagory. Was this the intent? If the intent was to capture those units with OVER-frequency trip setting above 61.8 Hz then the wording needs to be changed to "trip at or above 61.8Hz".The drafting team did a good job.
Response: Thank you for this comment. The SDT has modified these requirements to refer to frequency-time curves rather than specific thresholds, and has incorporated your suggestion to specifically refer to overfrequency and underfrequency trip settings.	
System Protection & Control	There needs to be clarification as to loads and generation in this standard. If the intent is for the System to be secure for loss of xx amount of generation at summer peak and at winter peak in the planning model then that should be stated. In short, there needs to be further clarification on the relationship in regards to compliance within the Planning Model and the actual System Loads and Generation. Some entities in some regions require compliance with load shed percentages real time, 24/7. Others, only for the summer peak, and others for both summer and winter peaks. While these questions relate to measurements, it would

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	be beneficial to know beforehand the SDT's thinking on these before implementation begins.
Response: The proposed standard leaves this aspect of UFLS program design to Planning Coordinators as long as the performance characteristics (now R3) are satisfied for the load levels assessed (R4).	
Duke Energy	--- Similar to the response for 5, the team should consider simplifying the requirements by stating points that are just an offset of the PRC-024 requirements. As noted in the webinar, the overfrequency points do not coordinate with the PRC-024 curve at
Response: Thank for your comment. Based on industry input the SDT has replaced the discrete points in the proposed standard with a continuous curve that provides consistent 0.2 Hz margin for time up to 60 seconds.	
Illinois Municipal Electric Agency	IMEA recommends the following language from the Background/Information section of the comment form be included under Section B. Requirements, R2: Planning Coordinators may elect to use their Regional Standards Development process to develop the programs (but this is not required) or they may determine that their existing programs fully meet the requirements of this proposed continent wide standard. **Response: The requirements in the standard are intentionally limited to what an entity must do to support a reliability need. While the SDT agrees that Planning Coordinators may elect to use the Regional Standards Development process to develop the programs, such explanatory text is not appropriate within a reliability standard.** IMEA believes the standard should only apply to areas where there are required UFLS programs that are in existence and not applied to all load if those loads are already covered in an existing UFLS program. **Response: To ensure reliability and uniformity of UFLS program objectives, all load must be considered in a UFLS program and all UFLS programs must meet the requirements of the proposed standard, regardless of how existing programs are implemented. This being said, Planning Coordinators have flexibility to make allowances for issues such as what the commenter raises.** IMEA also recommends that Regional Entities be directed to not include registered functions other than PC, TP, and DP in the applicability section of their region-specific PRC-006 standard. **Response: Regional Standards may assign applicability to entities not included in the continent-wide standard as long as requirements do not conflict with the continent-wide standard.**
Hydro-Québec TransEnergie (HQT)	HQT recommends that NERC develop standards for unit governing response that are consistent with and support the reliability objectives of standards PRC-006 (UFLS) and PRC-024 (Generator Performance). **Response: The SDT agrees, though this is outside the scope of its activities.** HQT also notes that it may not be possible for the Planning Coordinators to design a reliable UFLS program that will arrest and

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	recover declining frequency if an excessive number of generators are exempted from meeting the underfrequency performance requirements in PRC-024. **Response: The SDT agrees, though this needs to be addressed by the Project 2007-09 (Generator Verification) PRC-024 SDT. The current draft of PRC-024 does require documentation and response to technical review by other entities for any non-conforming trip settings.** HQT, being in the Québec Interconnection, has technical parameters that differ from those specified in Requirements R6 and R7. A Variance will be needed to address those specific concerns in regards to frequency tresholds and parameters. **Response: A variance for the Québec Interconnection is included in the third posting of the standard.**
AEP	Wouldn't PRC-006-01 R5 be a SPS with all of it's attendant liabilities. Isn't NERC trying to minimize SPS schemes? **Response: A relay scheme that intentionally separates a portion of the BES likely would be classified as a Special Protection System (SPS). However, the SDT points out that the proposed standard does not require implementation of such schemes. The standard only acknowledges that such protection schemes may be implemented and requires that in such cases the resulting islands must be included in assessments of the UFLS program design.** PRC-006-01 R5 and EOP 003-1 philosophy would need to agree. PRC-006-01 R5 is written from the standpoint that one is able to predict island formation whereas EOP 003-1 is written to respond to island formation in whatever form it takes by shedding load (EOP 003-1 R6). **Response: The SDT also notes that while PRC-006 requirement R5 (now R2) is written from the perspective that one is able to predict some islands to be used as a design basis for the UFLS program, the overall intent of the standard is to design a UFLS program capable of operating reliably in response to island formation in whatever form it takes. Nevertheless, the SDT agrees that PRC-006-1 and EOP-003-1 should not include duplicative or contradictory requirements. The SDT has requested and received Standards Committee approval to propose a supplementary SAR to modify EOP-003-1. The proposed supplemental SAR and conforming revisions to EOP-003-1 have been included with the third posting of PRC-006-1.** EOP 003-1's purpose is to protect the interconnection whereas PRC-006-01 R5 would seem to require opening up ties. There seems to be a disconnect here. However, if the UFLSDT does goes forward with this thinking, then AEP would suggest small island formation as likely being more successful than large island formation. **Response: As noted above, the proposed standard does not require opening ties.** Another interpretation of the two standards would be that PRC-006-01 R5 is intended to be designed as an automatic first option. If that option fails, then EOP 003-1 is to be followed by the transmission operator. **Response: The SDT believes the commenter's alternate interpretation of the differences between EOP-003 and PRC-006**

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	is correct. The SDT has proposed revisions to EOP-003-1 to clarify these differences.
Ontario Power Generation	The SDT should be commended for producing a very good standard. There is one issue however that may negate the outcome of UFLS effort. Maximum permissible frequency overshoot of 61.8 Hz specified in R6.3 appears too high. It would quite likely result in hard to predict loss of many large fossil and nuclear units. Past system disturbances provide enough evidence of such thermal power plant response that typically leads to system collapse. This is a fundamental issue for the design of an effective UFLS scheme. What was the reason for not adopting a lower frequency overshoot value, especially considering that multi-step UFLS schemes should be able to accommodate that?
Response: The 61.8 Hz limit on overshoot was selected to coordinate with the generator tripping limits proposed in PRC-024 by the Generator Verification SDT (GV SDT). The GV SDT developed the tripping limits to coordinate with generating unit capabilities as provided by a number of manufacturers. Therefore, this comment should be directed to Project 2007-09 SDT. The SDT notes that even with a multi-step program it may not be possible to limit overshoot to a lower threshold depending on the physical characteristics of the island such as inertia and frequency response.	
We Energies	We Energies disagrees with the overall approach that the Standard Drafting Team (SDT) has taken with the latest draft of the continent-wide UFLS standard. FERC rejected the original PRC-006 due to its fill-in-the-blank nature. The continent-wide standard is still a fill-in-the-blank standard with the Planning Coordinator (PC) required to fill in the blanks. **Response: The SDT disagrees that the proposed standard is a fill-in-the-blank standard. The existing PRC-006 requires that the RROs consider a list of items in developing a program. The proposed standard requires that Planning Coordinators design a UFLS program that meets specific performance characteristics. While the proposed standard is not specific on how the program should be designed, it does establish clear requirements on what performance characteristics the program must meet.** In addition, the standard does not require the PC to involve the Distribution Provider (DP) and Transmission Owner (TO) in the development of the UFLS program. Also, the standard requires the DP and TO to implement without question whatever UFLS program has been designed by the PC. **Response: While the standard does not require that the Planning Coordinators involve other entities, the Planning Coordinator must work closely with other entities in performance of its role. Regardless, the SDT believes the Planning Coordinator is the Functional Model entity with the wide-area view and technical skills required to perform the UFLS design and assessments. The SDT has not included a requirement to involve the Distribution Providers and the Transmission Owners in the process because it would be difficult to measure "involvement" and because this involvement is not required to fulfill the reliability objective of the proposed standard.** We are concerned that the standard places a burden on the DP and TO to shed additional load to make up for generators which trip outside of the criteria specified in draft NERC standard PRC-024. **Response: The proposed standard does not necessarily require the Distribution Provider and Transmission Owner to**

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	shed additional load as suggested by the commenter. The proposed standard allows Planning Coordinators to determine what measures will be included in the UFLS program design to account for the impact of generators with non-conforming trip settings. The current draft of PRC-024 does require documentation and response to technical review by other entities for any non-conforming trip settings. A continent wide UFLS standard must set the minimum level of UF tripping for each Interconnection. The continent wide standard must do this by specifying the minimum amount of loadshed, trip frequency steps, and time delay criteria for UFLS relays. **Response: The SDT disagrees with this statement. The SDT has proposed and industry comments have generally supported the concept of a responsible entity designing UFLS programs to achieve certain performance characteristics without the standard having to specify the UFLS program details and parameter values.** The continent wide standard must remain silent on criteria, such as islanding, that is above and beyond the minimum amount of loadshed, trip frequency steps, and time delay criteria. Regional UFLS standards must be the vehicle for going above and beyond the minimum requirements of the continent wide UFLS standard. Islanding is one aspect that can be addressed in regional standards if necessary. If the above comments are not adopted by the SDT, the following additional comments address the standard as written. **Response: The proposed standard is silent on performance characteristics for islands that may form with a generation-load imbalance greater than 25 percent.** As mentioned previously, this standard does not have a requirement for the PC to involve the DP and TO in the design of the UFLS program. In addition, the standard requires the DP and TO to implement without question whatever program the PCs design without any concurrence from the DPs and TOs. There must not be any loopholes in this standard which would force the DP or TO to shed additional load for a generator that could meet the criteria specified in draft NERC standard PRC-024. Therefore, R2 must be revised to add a sentence that requires the PC to involve the DP and TO in the design of a mutually agreeable UFLS program. Similarly, R10 must be revised such that it states that the DP and TO will implement the mutually agreed to UFLS program. **Response: As noted above, the SDT has not included a requirement to involve the Distribution Providers and the Transmission Owners in the process because it would be difficult to measure "involvement" and because this involvement is not required to fulfill the reliability objective of the proposed standard. Also, the SDT has decided not to be prescriptive as to what measures will be included in the program design to account for the impact of generators with trip settings that trip above the curve in PRC-024.** Lastly, in the RFC region there are only three PCs. This standard is placing a burden and regulatory risk on these three entities in RFC. It is not consensus for three entities to dictate a UFLS program for an entire region. **Response: As noted above, the SDT believes the Planning Coordinator is the Functional Model entity with the wide-area view and technical skills required to perform the UFLS design and assessments. The Planning Coordinator is also**

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	supposed to coordinate with other entities in the performance of its role. The SDT believes the Planning Coordinator is the appropriate entity regardless of the number of Planning Coordinators within a region. The last sentence of R4 needs two clarifications. First, the text neighboring entities needs to be defined. It is unclear if the text neighboring entities refers to a neighboring PC, DP, TO, GO, Region, etc. Second, the term assessment needs to be referenced in a more specific manner. Does the term assessment refer to island assessments or the UFLS program assessment required in R7 **Response: This requirement has been removed.** The last bullet item in R5 needs clarification. First, what is meant by the text at least one island? Does this mean the default island is the Region's electrical boundaries? **Response: R5 (now R2) has been modified to state that either the Regional Entity footprint or the interconnection must be identified as an island.** Second, if a DP or TO's load is part of multiple islands, what mechanism will prevent the DP or TO being issued conflicting UFLS trip settings (e.g. Island 1 requires the DP to set its relays to trip at 59.0 Hz, while Island 2 requires that same DP to set its relays to trip at 58.7 Hz)? **Response: The Planning Coordinator must design a UFLS program for application across its footprint and the program design must meet the performance characteristics for all islands studied. If there are still conflicting instructions, the matter should be resolved with the Planning Coordinator.** R7.1 and R7.2 need to be revised since as these sub-requirements are currently written all units with automatic UF tripping installed would be required to be simulated. Specifically, R7.1 requires units that trip between 58.0 Hz to positive infinity to be simulated and R7.2 requires units that trip between 61.8 Hz and 0 Hz to be simulated. **Response: These requirements (now Parts 4.1 through 4.6 of Requirement R4) have been revised such that Part 4.1 refers specifically to underfrequency and Part 4.2 specifically refers to overfrequency.**
Response: See in line responses.	
PacifiCorp	No comment.
NextEra Energy Resources, LLC	No comment.
American Transmission Company	ATC believes that the SDT should develop official definitions for the following three terms used throughout the document: a) "under-frequency load shedding" (along with under-frequency load shedding program) b) island and region. All three terms

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	warrant a definition in order to be able to assess whether the plans developed pursuant to the standards are consistent between and among the Planning Coordinators. Although these terms may have some generally accepted meaning, there likely is a difference among Planning Coordinators and those differences could potentially lead to enforcement issues. The failure to define these terms by NERC will result in each Planning Coordinator providing their individual perspective that could result in either gaps in the region or difference in what is meant by an island within a region, and what constitutes an under-frequency load shedding program. **Response: The SDT believes use of these terms is generally understood throughout the industry and unique definitions are not required in the NERC glossary. The SDT believes the meaning of "underfrequency load shedding" is already understood by industry in implementing the approved PRC standards. The term "island" is used exclusively to refer to a portion of the system that is isolated electrically from the rest of the system. The term "region" is used as it relates to the traditional sense of the defined boundaries of a Regional Reliability Organization (RRO). The term "region" has been replaced by "Regional Entity footprint" in the third draft.** R2 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall design . . . that was developed in coordination with the applicable regional group(s). **Response: The group of Planning Coordinators concept has been removed and the responsibilities have now been assigned to individual Planning Coordinators.** R2 - To allow appropriate UFLS program differences amoung islands within a single Regional Entity, we suggest this rewording, " . . . under frequency load shedding programs for consistent application across each island within the Region." Some islands in the MRO need to shed more load than other to achieve reasonable frequency recovery. **Response: The SDT has addressed this concern in an alternate manner by eliminating the word "consistent."** R3 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall develop . . . in coordination with the applicable regional group(s) to apply to select portions of the Bulk Electric System that are designated as islands?.R4 To make the requirement apply to each PC rather than a group and include corordination within the Region, we suggest this rewording, Each Planning Coordinator shall develop a procedure for coordinating with groups of Planning Coordinators within its Region(s) and groups of Planning Coordinators in neighboring regions . . .R5 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall identify . . . as a basis for designing a UFLS program with the applicable regional group(s) R6 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall specify . . . load shedding program in coordination with the applicable regional group(s) that are required to meet the following . . . **Response: As noted above, the group of Planning Coordinators concept has been removed and the responsibilities have now been assigned to individual Planning Coordinators.** R6.1 To match the design emphasis that is included in R6.2 and R6.3, we suggest . . . no less that 58.0 Hz per simulated event.

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	Response: The SDT has revised these requirements to refer to frequency-time curves rather than specific thresholds and time durations. The SDT believes that the revised requirements (now Parts 3.1 and 3.2 of R3) address the commenters' concern. R7 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall conduct . . . with its applicable regional group(s). R8 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall create . . . in coordination with its applicable regional group(s) . . **Response: As noted above, the group of Planning Coordinators concept has been removed and the responsibilities have now been assigned to individual Planning Coordinators.** R8 - Since the interpretation of "annually" can vary widely, we suggest this rewording, "each calendar year and within 15 months of the last update". **Response: Since "annually" is not defined a NERC term, it has the meaning "occurring or happening every year or once a year." as found in a collegiate dictionary. The SDT believes the reliability objective of this requirement is met without specifying details of when during the year the requirement is fulfilled.** R9 Since the Transmission Owner reference is redundant, we suggest this rewording, Each Distribution Provider shall provide.. .. **Response: The SDT has decided to retain both the Distribution Provider and the Transmission Owner as UFLS entities in the applicability for this requirement. The drafting team provided the rationale for keeping Transmission Owner in response to comments to Question 1B.** R10 Since the Transmission Owner reference is redundant, we suggest this rewording Each Distribution Provider shall provide . . . **Response: The SDT has decided to retain both the Distribution Provider and the Transmission Owner as UFLS entities in the applicability for this requirement. The drafting team provided the rationale for keeping Transmission Owner in response to comments to Question 1B.** R11 - Since reactive power device overvoltage or underfrequency protection may be essential to the UFLS program assessment, we suggest adding the Requirement, "R11. Each Distribution Provider and Transmission Owner shall provide its reactive power device overvoltage or underfrequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section. **Response: The database is intended to document the load tripping implemented by Distribution Providers and Transmission Owners to meet Requirement R9. In fulfilling the Planning Coordinator function, the Planning Coordinators have the ability to obtain protection settings they need to model to comply with R4 and R11. Planning Coordinators and Transmission Planners routinely obtain similar data to perform planning studies required by the Transmission Planning (TPL) standards.** R12 - Since reactive power device overvoltage or underfrequency protection may be essential to the UFLS program design, we

Organization	Question 8 Comments:
	suggest adding the Requirement, "R12. Each Distribution Provider and Transmission Owner shall reactive power device tripping in accordance with the UFLS program desinged by the group of Planning Coordinator for each region in which they operate." **Response: The SDT has added a new requirement R10 that requires Transmission Owners to provide automatic switching of Elements in accordance with the UFLS program design. The SDT believes this general requirement is more appropriate to include both energizing and de-energizing reactive devices or any other system Elements when included by the Planning Coordinators as Part of the UFLS program design.** R13 - Since generator off nominal frequency protection information may be essential to the UFLS program assessment, we suggest adding the Requirement, "R13. Each Generator Owner shall provide its off nominal frequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators." R14 - Since the coordination of generator off nominal frequency protection is essential to the UFLS program design, we suggest adding this Requirement "R14. Each Generator Owner shall have evidence that they provided any coordination that is required by the applicable regional group of Planning Coordinators to meet UFLS program specifications." **Response: The SDT does not believe these requirements are necessary. Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. Adding such a requirement in PRC-006-1 will create a redundant data requirement already contained in PRC-024-1. Coordination is not required from Generator Owners, but PRC-024 does require documentation and response to technical review by other entities for any non-conforming trip settings.** Reference Document - Due the number and complexity of the elements that need to be considered to develop effective UFLS program designs and for fulfilling the requirements in this standard (e.g. island identification, number of load tripping steps, frequency settings, time delays, percentage of load per step, system inertia, governor response, etc.), we suggest that a reference document be developed to provide useful information regarding automatic UFLS programs to the applicable entities. **Response: The SDT appreciates the complexities of designing a UFLS program; however, the SDT notes that regional UFLS programs have existed for forty years and believes that the Planning Coordinators have adequate expertise to understand the requirements of the proposed standard.**
Luminant Power	Several of the requirements are for a group of Planning Coordinators. From a Compliance perspective, how will the actual requirements be enforced on the group, or will the requirements be enforced on each individual Planning Coordinator? **Response: The group of Planning Coordinators concept has been removed and the responsibilities have now been assigned to individual Planning Coordinators.**
Ameren	There is nothing in the standard that provides direction in terms of measuring whether an entity has effectively implemented a

Organization	Question 8 Comments:
	UFLS program.
Response: Requirement R9 requires that Transmission Owners and Distribution Providers provide automatic tripping of load, and Requirement R10 requires that Transmission Owners provide automatic switching of Elements in accordance with the UFLS program designed by the Planning Coordinator. These requirements establish that the Distribution Providers and the Transmission Owners must implement what is required of them according to the UFLS program design.	
FirstEnergy Corp	1) On requirement R7.1 we suggest adding the words under-frequency before the phrase trip settings for clarity. **Response: This requirement (now Parts 4.1-4.3 of Requirement R4) has been revised such these Parts refer specifically to underfrequency.** 2) On requirement R7.2 we suggest adding the words over-frequency before the phrase trip settings for clarity. **Response: This requirement (now Parts 4.4-4.6 of Requirement R4) has been revised such that these Parts refer specifically to overfrequency.** 3) As stated in question 5, the frequency requirements for generators should be in this standard PRC-006 not PRC-024. **Response: The SDT disagrees and has coordinated with Project 2007-09 SDT such that Generator Owner frequency and voltage Requirements can appear in one place (in PRC-024). Coordination between the two SDTs is expected to accomplish the same reliability objectives as if the frequency requirements for Generators Owners were in PRC-006.** 4) The new standard does not properly address the requirements of PRC-009 to analyze the performance of an UFLS program following an under frequency event. If the standard is retire PRC-009, it needs to properly cover the analysis of these events and not refer them to ERO Rules of Procedures. Since PRC-004 covers the analysis of System Protection misoperations and PRC-016 covers SPS misoperations, UFLS events including misoperations also must be covered in a standard to ensure review. **Response: The SDT has added a requirement to include an assessment of the performance of UFLS equipment and the UFLS program effectiveness (Requirement R11) within one year of an actuation of UFLS resulting in a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program.** 5) On requirement R.1 the use of the word region should be replaced with Regional Enity territory for clarity so that region may not be misinterpreted to be RTO region or some other sub-region of a Regional Entity territory. We suggest the requirement be written to say Each Planning Coordinator shall join a group consisting of all Planning Coordinators within the Regional Entity territory it performs the Planning Coordinator function. **Response: The term "region" is used as it relates to the traditional sense of the defined boundaries of a Regional Reliability Organization (RRO). The term "region" has been replaced by "Regional Entity footprint" in the third draft.** 6) We support the following MISO comment. R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a

Organization	Question 8 Comments:
	PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria. Response: The SDT recognizes the difficulties that could be encountered in identifying islands. Nevertheless, there may be portions of a system that obviously have a higher likelihood of islanding as compared to others. How extensive an analysis to identify islands needs to be is a judgment that cannot be written into a standard and must be left to the discretion of the Planning Coordinators involved. The standard only requires that criteria for identifying islands be developed, documented and applied.
CenterPoint Energy	1. CenterPoint Energy again commends the SDT for addressing the difficult issue of Applicability. CenterPoint Energy suggests the SDT also address the difficult issue of placing requirements within the proper category of reliability standard. CenterPoint Energy recommends placing Requirement 9, dealing with submittal of UFLS data, within a MOD standard (Modeling, Data, and Analysis). CenterPoint Energy believes the UFLS data will be used for modeling to facilitate dynamic simulation studies and, therefore, should be included in an MOD standard. **Response: The SDT does not disagree with the commenter, but including the requirement in the MOD project may create a reliability gap if the MOD project is not completed before or at the same time as the UFLS project. As a result, the SDT feels that this requirement needs to remain in this standard, at least for the present time.** 2. CenterPoint Energy appreciates the SDT attempt to clarify islanding. However, the SDT may have misinterpreted CenterPoint Energy comments on Draft 1. Reiterating our comment, CenterPoint Energy believes regional and/or predetermined islanding is not always applicable in an interconnection-wide region. In addition, the requirements dealing with a group of Planning Coordinators are also not applicable to an interconnection-wide region, such as WECC and ERCOT. With eight of the ten proposed requirements applicable to a group of Planning Coordinators, it appears eight requirements will be problematic for WECC and ERCOT. CenterPoint Energy recommends the following wording be included in Requirements 1 through 8: This requirement is not applicable in an interconnection-wide region. **Response:** The SDT recognizes the difficulties that could be encountered in identifying islands. Nevertheless, there may be portions of a system that obviously have a higher likelihood of islanding as compared to others. How extensive an analysis to identify islands needs to be is a judgment that cannot be written into a standard and must be left to the discretion of the Planning Coordinators involved. The standard only requires that criteria for identifying islands be developed, documented and applied. **The group of Planning Coordinators concept has been removed and the responsibilities have now been assigned to individual Planning Coordinators.**
Independent Electricity System Operator	(1) We propose R5 to be expanded to require the Planning Coordinators to develop criteria for identifying potential islands, as follows: Each Planning Coordinator shall develop criteria, considering historical events and system studies, to select portions of the Bulk Electric System (BES) that can form an island(s) as a basis for designing a UFLS program. The identified island(s) shall

Organization	Question 8 Comments:
	include: **Response: It is unclear if the commenter is suggesting that the requirements to develop criteria and to identify islands should be combined into one requirement. If so, the SDT thinks that these two requirements cannot be combined into one requirement because they are describing two separate activities.** (2) R6 needs to be more precise regarding load. Suppose a station with 100MW of load has 20MW of distributed generation added that is anticipated to be in service during the ULFS calculation period (e.g. summer peak hour). Is the ULFS arming determined on basis of 100MW or 80MW of load This will make a big difference in Ontario if the GEA attracts significant amounts of the distributed generation. **Response: The load in the imbalance equation Requirement R6 (now R3) is based on the Planning Coordinator's load forecast which should be reflected in the power flow model. The 25 percent load-generation imbalance requirement should be consistently applied even if some generation is netted with load. The actual arming would be in accordance with the load amounts specified by the UFLS program designed by the Planning Coordinator.** (3) The standard should include a requirement for mandatory testing/re-calibration period for both ULFS relays and generator under and over frequency relays. The Generator Operator/Owner needs an obligation to provide this information. **Response: Testing and recalibration of relays is addressed by the Protection System Testing and Maintenance SDT (Project 2007-17) in PRC-005-2.** (4) Governor action can help mitigate adverse effects of disturbances that affect frequency. Should this standard include some requirements for governor response? **Response: The SDT agrees that governor response has a direct impact on recovering frequency and controlling frequency overshoot. However, specifying requirements for governor response is outside the scope this standard. The UFLS program must be designed to meet the performance characteristics for whatever level of governor response is present on the system.**
Xcel Energy	We feel R6.4 is not complete without consideration of other BES components, such as transformers and reactive devices. To ensure excessive voltage does not cause further damage or perpetuate the situation, we feel these additional components should be considered. **Response: The reliability objective of this performance characteristic in Requirement R6 (now Requirement R3) is to prevent tripping of generation that would exacerbate the load-generation imbalance. This is the reason the SDT focused on generator busses and generator step-up transformer high-side busses in requirement R3 Part 3.3. The SDT believes that observance of overvoltage limits on other equipment should be addressed by other standards, not a UFLS standard.** We feel that the use of the word region in R1 is unclear. We assume the SDT intended to refer to the 8 NERC regions? (MRO,

Organization	Question 8 Comments:
	SPP, WECC, RFC, SERC, etc.) If so, please make that clear in the requirement. **Response: The SDT intended "region" to relate to the traditional sense of the defined boundaries of a Regional Reliability Organization (RRO) and its successor the Regional Entity. The SDT feels that the concept of a "region" is generally understood throughout the industry and does not believe that a unique definition is required. The term "region" has been replaced by "Regional Entity footprint" in the third draft.**

1) Individual or group.
Individual

2) Name
Barry Francis

3) Organization
Basin Electric Power Cooperative

6) NERC Region (check all Regions in which your company operates)
MRO
WECC

7) Registered Ballot body segment (check all industry segments in which your company is registered)
1 - Transmission Owners
3 - Load-serving Entities
5 - Electric Generators

Summary Considerations:

The SDT believes that what is behind the majority of the commenter's comments is a concern over sub-regional UFLS programs that need to be substantially more than 25 percent.

First, the SDT would like to clarify a possible misconception held by the commenter: The performance characteristics in R6 (now R3) of the draft PRC-006 standard would NOT apply to UFLS program percentages and load-generation imbalances over 25 percent. It is correct that the generator off-nominal frequency tripping limits contained in the draft PRC-024 standard would apply at any UFLS percentage and imbalance. However, a UFLS program capable of shedding more than 25 percent of a system's load would only need to comply with the performance characteristics up to a 25 percent load-generation imbalance. Beyond a 25 percent load-generation imbalance, a UFLS program would not be subject to any NERC imposed requirements, although the Planning Coordinators within a region could devise other performance characteristics that would apply under load-generation imbalance scenarios greater than 25 percent.

The SDT understands the concern over bigger sub-regional UFLS programs. The SDT recognizes that Planning Coordinators in a region with a 60 percent capable UFLS program, for example, may have trouble complying with the performance characteristics even under a 25 percent load-generation imbalance scenario. The SDT is not convinced that it would be impossible to comply, but can see that it could be more difficult. In response to this concern the SDT did modify the underfrequency performance characteristic (part 3.1 of Requirement R3) noting that some entities may have difficulty recovering frequency within 30 seconds. Assessments that demonstrate the reliability objective of PRC-006 can be met without meeting the performance characteristics in Requirement R6 (now R3) could be used to support a request for a regional variance.

The commenter does not seem to acknowledge the need for coordination among interconnected regions, a consideration that has weighed heavily in the SDT's deliberations. This may be because coordination can become troublesome in the presence of bigger programs. A bigger program in an exporting sub-region with limited interconnecting transmission, for example, is likely to set up further system separations should a UFLS event occur across a larger area. On the other hand, a bigger program in an importing sub-region should not cause coordination difficulties. The SDT has determined that the approach that is least intrusive on the flexibility to set UFLS design parameters within a region, but that addresses the need for inter-regional coordination, is to establish continent-wide performance characteristics as are now in the draft standard.

The SDT disagrees that there is a need to radically modify the two standards (PRC-006-1 and PRC-024-1) as the commenter is suggesting. Most of the North American systems have UFLS programs in the 25-30 percent of load range and should have no difficulty in complying with the draft performance characteristics. The Planning Coordinators within a region are not obligated by the draft standard to constrain the size of sub-regional programs for the sake of interregional coordination or any other reason. If necessary, a regional variance may be proposed.

The commenter's comments on PRC-024 seem predicated on an assumption that GOs will set their relays on this curve. The SDT suggests the commenter comment on the draft PRC-024 standard on this point. Nonetheless, generator underfrequency tripping curves are not new. The MRO region, even today, has such a generator underfrequency curve (stair-step) that fairly closely tracks the draft PRC-024 curve. Therefore, the SDT is not certain that the commenter's comments regarding

coordination of UFLS with generator tripping and elimination of these curves has been found necessary even in regions having sub-regional UFLS programs substantially greater than 25 percent. (Note: the commenter should re-review draft PRC-024 Attachment 1, Off-Nominal Frequency Capability Curve, because the time durations are longer than what the commenter has assumed in the commenter's Question 5 comments and in section 2.17 of Question 8 comments.)

8) Question 1a
Do you agree that creating a continent wide standard preserves the intent of utilizing specific expertise within the regions to develop UFLS programs that meet common performance characteristics? Yes

Summary of Issues - Question 1:

- Technical approach is inappropriate and the team should provide its technical justification for the performance criteria

  Response: The SDT disagrees that the technical approach is inappropriate. The technical justification for the performance characteristics lies chiefly in their coordination with generator under-frequency tripping limits in draft standard PRC-024, which in turn are based on turbine manufacturer's permissible life-time durations at off-nominal frequencies.

- Agrees that planning coordinators are the appropriate entity to establish the program; however, there are shortcomings to this approach – limited scope and should include subject matter experts (the planning coordinator may not be the subject matter expert). The Regions should remain involved in the process of developing the programs as they have the committee structure in place to accomplish.

  Response: The SDT thanks the commenter for his support; however, does not see an alternate approach to assigning responsibility to the Planning Coordinator. FERC Order 672 indicates that requirements should be assigned to users, owners, operators of the bulk electric system and while the SDT agrees that the Regional Entities should be involved, the drafting team can only assign the responsibility to the Planning Coordinator (a user, owner, operator). The drafting team feels that it has not precluded the involvement of the Regional Entity in the process nor precluded the Planning Coordinator(s) from electing to use their regional standards development (process as an open and inclusive process to establish the program.

9) Question 1a Comments:
See my detailed discussion under item 8, in it's entirety, but especially my sections 3.5 and 3.6. I believe a continent wide standard may be possible if we adopt a completely different type of measure but we cannot be setting performance details up front before the study work has been performed. Different sizes of programs have different performance characteristics, so a single set of performance characteristics will not meet the needs of all parts of North America.

Response: See SDT answer under Summary Considerations above. Most North American systems have UFLS programs in the range of 25-30 percent of load. If a sub-regional UFLS program substantially exceeding this range cannot comply with the performance characteristics for load-generation imbalances up to 25 percent, a regional variance should be proposed.

10) Question 1b
Do you agree that the SDT has assigned responsibility to the appropriate entity? No

11) Question 1b Comments:
I do not know for sure if responsibilities are assigned to the appropriate entity, so I answered NO, when "I do not know" might have been more appropriate. To some degree, everyone needs to get involved at some level to ensure we have a loading shedding program in place to act as a saftey net. I am concerned that the transitions associated with "mandatory compliance" appears to actually be decreasing the level of coordination we have traditionally had. Good coordination is the key to ensuring reliability. Among other things, we need to keep the NERC regions involved in this process. They have the committee structure to facilitate coordination matters, and they can bring everyone together to jointly focus on the issues.

Response: The Standard Drafting Team does not see an alternate approach to assigning responsibility to the Planning Coordinator. FERC Order 672 indicates that requirements should be assigned to users, owners, operators of the bulk electric system and while the SDT agrees that the Regional Entities should be involved, the drafting team can only assign the responsibility to the Planning Coordinator (a user, owner, operator). The drafting team feels that it has not precluded the involvement of the Regional Entity in the process nor precluded the Planning Coordinator(s) from electing to use their regional standards development process as an open and inclusive process to establish the program.

12) Question 2:
The SDT has strived to draft the applicability in a manner that includes all load while avoiding assigning applicability to more than one entity for the same load. The Functional Model indicates the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. Considering the Functional Model definition of Distribution Providers please indicate whether you believe it is necessary to assign applicability to "Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of a Distribution Provider's load". No

13) Question 2 Comments:
It seems OK to consider transmission owners with end-use load connected to their Facilities as Distribution Providers, but I can see complications. How does a transmission owner with a small amount of end-use load have enough load to work with to satisfy the load shedding program description? This implies they would have to coordinate with someone else. Taking this concept further, it seems like we need to ensure the right program is implemented in aggregate, but not worry too much about each responsible party meeting the exact program specification. We can take advantage of one party shedding a little too much at one stage and another shedding a little less to get the right fit in the end. This is sort of taking advantage of offsetting errors. This implies some type of group coordination based on geographic area is needed to ensure the collective load shedding need is fulfilled.

Response: The SDT acknowledges that entities with a small amount of end-use load could have difficulty shedding load in several small steps. The proposed standard only requires that the Distribution Providers and Transmission Owners follow the program developed by the Planning Coordinators in their region and does not specify the program requirements. The SDT believes it is appropriate to allow the Planning Coordinators in each region to address potential concerns related to small entities by the means they deem most appropriate. The SDT has also revised the applicability in Draft #3 and this revision may address the commenter's concerns in part.

Summary of Issues – Question 3:

- Planning Coordinators should determine the appropriate analysis. As written, the implication is that a full transient stability program is needed to do this analysis. There are other equally valid analytical approaches, each with different strengths and weaknesses, and the group of Planning Coordinators should be allowed to use whatever tools they feel are most appropriate for quantifying this risk.

  Response: The Planning Coordinators are permitted to use whatever methods, tools and analyses they wish to use in coming up with the UFLS program design and parameters. The draft standard would only require dynamic simulations of the whole regional system or the islands in the periodic UFLS assessments (now R4). The SDT believes that dynamic simulations are the most dependable means of assessing compliance to the performance characteristics. Equivalent inertia analysis would not include the effects of island initiating disturbances on localized frequency and voltage, inter-machine oscillations, or the particular response of individual unit governors.

- Should try to prevent units from tripping off before the UFLS program plays out

  Response: The SDT agrees, but the only way to ensure that units don't trip before UFLS plays out is to set coordinated requirements in standards. On this matter, PRC-024-1 is the applicable standard for establishing generator tripping requirements and PRC-006-1 establishes coordinated UFLS program performance characteristics.

14) Question 3:
The proposed continent-wide standard requires that Planning Coordinators model the trip settings of any generators that trip at or above 58.0 Hz (Requirement R8) when verifying through dynamic simulation that the UFLS program design is adequate to meet the continent-wide performance characteristics specified in Requirement R6.

Do you agree with this approach to ensure that effectiveness of the UFLS program is not jeopardized by units that trip at or above the minimum frequency (58.0 Hz) at which the UFLS program may arrest frequency decline? No

15) Question 3 Comments:
Some type of risk assessment is needed, but a dynamic simulation may not always be appropriate if there are other ways to get the answer we are looking for. This subject, and related topics, are addressed in the comprehensive discussion I included under item 8. Please consider all of my comments under item 8 to understand my concerns.

First of all, in some instances a regional (or sub-regional) load shedding program sheds more than the required minimum of load. A consequence is the expected minimum transient frequency will probably be below 58 Hz, at least for some set of conditions, so we are going to interpret "58 Hz" as 58 Hz or the minimum expected transient frequency of the regional (or sub-regional) program. This revised definition is what we consider to be important.

Some of the older wind generation will trip early due to inherent instability of that type of induction generation. This is not a planned activity, but it is still loss of additional generation. In MRO we felt the present magnitude of this impact was small (and unpredictable) and it could be included as part of the original assessment of the total load shedding requirement. (This will have to be reconsidered as additional wind generation is added.)

MRO expects that newer wind generation and virtually all of the conventional generation will be able to accommodate the generation off-nominal frequency tripping time delay requirements proposed by MRO. As far as we are aware, it appears the sole exception are owners of one model of gas turbine who may want to trip instantly at frequencies such as 58.2 Hz rather than accept brief dips below 58.2 Hz. In WECC, owners of similar units managed to comply with the comparable WECC generation off-nominal frequency tripping time delay standard. We hope this will be how it plays out in MRO after owners of these types of gas turbines take a closer look and their options.

MRO does not encourage the practice of premature tripping of generation but we made a provision in the MRO UFLS program definition to allow premature tripping on underfrequency provided it meets certain provisions. This provision also applies to small non-utility generation which might be on a feeder that is tripped with load. Basically we require a nearly identical size block of load to be shed at nearly the same time and location to compensate. Owners who wish to do this should have some responsibility to demonstrate they can satisfy this provision. The burden of proof should be on those who want an exclusion.

At this point we believe that the group of Planning Coordinators (or the applicable study group in general) should decide on the appropriate analysis method to review impacts. They can decide if such loss of additional generation is significant or not. If we are only dealing with one or two small units on a large system, then this hardly needs further study other than to demonstrate it is feasible to trip additional load at the time the generation trips. As far as assessments go, we feel there are various approaches that can be taken to do this type of risk assessment. As written, the implication is that a full transient stability program is needed to do this analysis. There are other equally valid analytical approaches, each with different strengths and weaknesses, and the group of Planning Coordinators should be allowed to use whatever tools they feel are most appropriate for quantifying this risk.

There are even ways to assess the risk of having units trip off early that do not rely on simulations, but instead just quantify the additional overload burden this adds to the island.

Let engineers figure out how to study the problems using whatever tools, methods, and calculations they feel are appropriate. However, as a general principle, we should try to prevent units from tripping off before the UFLS program plays out. Even more important, we should not allow any generation to trip via dedicated overfrequency relays (other than tripping actions directly or indirectly related to the inherent factory installed load rejection protection that we do not want to be messing with). The one exception would be when overfrequency tripping of generation is a planned activity that is a feature of the UFLS program used to rebalance load and generation.

16) Question 4:
The SDT added a requirement that requires the Planning Coordinators model, in the five year assessments, any automatic load restoration that is designed to assist in stabilizing system frequency (Requirement R9). The team decided to add this requirement as a result of a comment during the first posting. Do you agree that this requirement is necessary for reliability?
Yes

17) Question 4 Comments:
Any automatic feature of the load shedding program should be modeled in the ULFS Program assessment.

Response: The SDT agrees.

18) Question 5:
The SDT added a requirement in the underfrequency load shedding performance characteristics that requires (in simulations) frequency to not remain below 58.2 Hz for greater than four seconds cumulatively per simulated event (Requirement R6.2). The

SDT added this requirement to better coordinate with the Generator Verification Project (PRC-024) tripping curve. Do you agree with this additional requirement? No

Summary of Issues – Question 5:

- The team should provide technical justification for the performance criteria

  Response: The technical justification for the performance characteristics lies chiefly in their coordination with generator under-frequency tripping limits in draft standard PRC-024, which in turn are based on turbine manufacturer's permissible life-time durations at off-nominal frequencies.

- Overall load shedding performance and coordination with generation protection should be evaluated at the regional level (not continent wide level – inferred)

  Response: The creation of a continent-wide standard does not prohibit the creation of Regional Standards for UFLS. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. This approach still allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.

- Canadian portion of MRO cannot meet the performance criteria and MRO cannot meet the timeframe established in requirement R6

  Response: The standard has been revised with input from MRO. Please see R3 and Attachments 1 and 2 in Draft #3.

- Setting specific off-nominal frequency limits / criteria up front effectively sets the limit on how much load can be shed and drives all load shedding programs to the lowest common denominator which will reduce reliability

  Response: The SDT disagrees. For imbalances up to and including 25%, these performance characteristics must be met; however, the proposed standard does not include requirements for imbalances exceeding 25%. If a region wishes to design an UFLS program to cover imbalances exceeding 25%, the region's Planning Coordinators may develop other performance requirements through Regional Standards, Regional Variances, or Regional Criteria as outlined in the NERC Rules of Procedure.

19) Question 5 Comments:

Please provide the technical justification for this performance criteria.

This subject, and related topics, are addressed in the comprehensive discussion I included under item 8. Please consider all of my comments to understand my concerns.

We understand the SDT wants to ensure load shedding programs achieve quick frequency recovery and minimize underfrequency exposure. However we do not feel this requirement is the right way to go about that. This type of criteria is overly specific and should not be in the NERC standard. The recently developed MRO UFLS program which sheds 30% of system load appears to meet this criteria, but the Canadian portions of MRO which have higher load shedding requirements are unlikely meet this criteria. Aggressive load shedding programs in general will probably not satisfy this requirement. Frequency recovery, overall load shedding performance, and coordination with generation protection, should all be evaluated at the regional level by those who do the technical analysis of regional load shedding programs. In addition to study work, a lot of common sense needs to be applied. Several things need to be discussed to clarify our position.

First of all, we do not agree with the direction taken in PRC-024 to define off-nominal frequency settings for generation. That should never have been included as part of PRC-024. No technical justification was ever provided for the generation protection frequency setpoints and time delays suggested in PRC-024, and those setpoints and delays do not necessarily reflect actual equipment capabilities. NERC should not be defining generation off-nominal frequency protection standards such as those in PRC-024 unless this is only intended to be a starting point that can be adjusted, as needed, based on results of actual study work. It takes study work to define the expected worst case frequency recovery times of the load shedding program and off-nominal frequency exposure is strongly affected by the size of the load shedding program. Setting specific off-nominal frequency limits/criteria up front effectively sets the limit on how much load can be shed and drives all load shedding programs to the lowest common denominator. Obviously that will reduce reliability. Programs which shed more than the minimum required load will inherently experience lower frequencies and spend more time below 58.2 Hz.

We believe that load shedding program design should be based on achieving the quickest frequency recovery that is possible

subject to satisfying all of the other conflicting design requirements and constraints, such as minimizing overfrequency problems, and in the end you are left with the engineering realities of what settings are needed on turbine/generator protection to achieve coordination. The folks who do the analysis at the Region level are in the best position to judge what is appropriate in the end. Final recommendations for turbine/generator protection will involve trade offs and compromises that have to be resolved by engineering judgment and a good deal of common sense.

We would like to point out that the risk to generation is somewhat less than implied by the generation underfrequency protection time delay settings and that being too conservative on the generation protection side will be a risk to system reliability. Consider that if premature generation tripping occurs that we are likely to initiate cascading loss of generation and go black. (The real loss of life exposure to power plants might be the restoration process of a black start plan, a plan which usually calls for this underfrequency protection to be disabled up front so they can pick the pieces back up.) In the context of a load shedding event, the risk to units is based on actual off-nominal frequency exposure, which is inherently something of a probability density function. For any load shedding program there are going to be certain combinations of overload and modeling assumptions where UFLS programs tend to stall out or where frequency recovery is sluggish. Think of this as narrow windows of vulnerability. For the majority of the conditions modeled, the frequency recovery is much quicker. A well designed UFLS program which is designed to force frequency recovery back towards 60 Hz can actually act as the first line of defense for generation and this is how the new MRO program was designed.

Even more troubling to MRO, and this should be equally troubling to all of the NERC Regions, are the very short time delays the PRC-024 has proposed at the higher frequencies (below 58.5 Hz for <= 10 seconds, below 59.3 Hz for <=30 seconds). In the MRO program design work, for the US portion of MRO where we have the smallest load shedding requirement, we spent approximately 8.7 seconds to 1.4 seconds below 58.5 Hz depending on what was assumed for governor response and other modeling details. The 10 second requirement for 58.5 Hz was just barely satisfied but keep in mind that we also want to set generation trip times so we have some comfortable margin between expected frequency recovery times and generation trip delays in case "real world" complications slow down frequency recovery. Likewise case work shows we will be below 59.3 Hz for 58.4 seconds to 42.5 seconds depending on governor action and other modeling assumptions. This is longer than the proposed 30 second limit. The final recommendation of the MRO program was to require generation protection to have a minimum of a 300 second delay for the frequency band between 59.0 Hz and 59.3 Hz (10 times the delay recommended in PRC-024), and a 45 minute delay for the band between 59.3 Hz and 59.5 Hz (270 times the delay recommended in PRC-024). Further, we recognize that programs which shed more than 30% of load will need to relax these settings and accept greater time delays. Keep in mind the MRO program was designed to work even if we get no net governor type of action as we use additional small blocks of load shed on delay to kick us towards 60 Hz if recovery is slow. We felt we got the quickest frequency recovery that was possible subject to all the other constraints we had to deal with, like limiting overfrequency and achieving relay coordination. We factored in considerable uncertainly into the design, but what may happen in the real world when everything else is going wrong can be chaotic and cannot always be anticipated. All of us in the industry really need to consider that when deciding how to set generation off-nominal frequency protection. Units can accept considerable time at frequencies closer to 60 Hz, and can generally operate continuously at +/- .5 Hz off of 60 Hz. The time delay associated with the 59.3 Hz setting proposed in PRC-024 is only 30 seconds which is way shorter than actual equipment capability (based on a reasonable accelerated loss of life per event). The system should be capable of operating at 59.3 Hz in excess of 30 minutes. In real life you would never want to set generation protection with a 30 second delay at 59.3 Hz. That is bound to cause trouble. In real life, the unexpected is going to eventually happen and our "perfect program on paper" will get a reality check. If frequency stalls out around 59.3 Hz, the actual equipment capability allows enough time for system operators to take manual actions. The proposed time delay in PRC-024 is too small to allow manual actions. Some may think that with a perfect automatic UFLS program that we can design things so this will not happen. Wrong, things can always get worse, Murphy's Law applies. We recognize that even the best UFLS program can fail in real life as everything else goes wrong out on the system. All load shedding gives us is a good chance of survival, but we can never assure ourselves it will always work as desired in the face of the unexpected. We need to constantly anticipate what can go wrong and eliminate as much of this inherent risk as we can, but we can never provide a safety net that will work for all modes of system failure. Here is a real world example of how we could stall out at some frequency such as 59.3 Hz (or any other frequency below 60 Hz for that matter). When load shedding occurs, there is a chance the system may break up further as tie lines between remote generation and load centers become over taxed and the two systems may lose synchronism (this cannot always be anticipated up front). The result is that subislands form where one is now surplus in generation and one has too much load. The island which is surplus in generation is now at risk of losing generation on overspeed (probably due to internal problems at each plant, especially thermal plants, that lead to random tripping that is nearly impossible to quantify). Once generation trips the island will plunge into a 2nd round of underfrequency. Fortunately loss of the first unit might allow the others to survive (i.e. steam valves can open back up) so the final imbalance might still be manageable. However in this instance, the region has already used up part or all of the automatic load shedding capability. With luck this island will settle out at some frequency where operators will have enough time to manually drop load to force frequency recovery before generator underfrequency protection trips. Once generation underfrequency protection trips the first unit, the system will cascade and go black. To give enough time to do manual load shedding at this higher frequencies, you need to set long time delays on the frequencies closest to 60 Hz.

Summary of Issues – Question 6:

- The team should provide the technical justification for BES busses at 20 & 75 MVA criteria

  Response: The SDT has considered all industry input and has decided not to modify the requirement. Although there are differing views on the question of how small a generator must be before its tripping does not have a material impact on system or island frequency, the SDT has decided that it is sufficient to require the monitoring of V/Hz at generators consistent with the NERC Statement of Compliance Registry Criteria. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity, which the team believes is sufficient accuracy for assessments of UFLS programs. The SDT also has decided to modify Requirements R7.1 and R7.2 (now parts 4.1 and 4.2 of Requirement R4) to apply to the same generating units and plants.

- The v/Hz requirement does not belong in this standard ("load shedding document") – IEEE standards already exist to address v/Hz.

  Response: This requirement supports reliability and the majority of the commenters indicated their support. IEEE standards do not restrict V/Hz during UFLS events; they only establish generator protection guidelines. While it may be unusual for generators to trip on V/Hz protection during UFLS events, the risk is still present, and a region's UFLS program design should not cause excessive levels of V/Hz at or near significantly sized generators to the degree that may cause them to trip. Therefore, the SDT has retained this requirement.

20) Question 6:
In the first posting, the Characteristics of UFLS Regional Reliability Standards required that UFLS programs be designed to limit the potential for overexcitation (V/Hz) of power system equipment at all Bulk Electric System buses. Based on industry comments, the SDT has revised this requirement in the proposed continent-wide standard to apply only at generator buses and generator step-up transformer high-side buses associated with individual generating units greater than 20 MVA (gross nameplate rating) and generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) that are directly connected to the BES. The SDT believes this change better addresses the need to have UFLS programs designed to coordinate with protection that may trip generators during an underfrequency event. Do you agree with this change? No

21) Question 6 Comments:
Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit. It also seems this only applies when frequency drops below 57.2 Hz. This is discussed further in my comprehensive discussion included in item 8.

This requirement should not be included because this is not a major concern. Assuming we want to study this, we will find this cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation.

The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document. During an under frequency event, generators should be working to pull voltages down anyway.

Please see response to question 8 regarding overvoltages related to tripping load without tripping capacitors.

Summary of Issues – Question 8:

- Continent wide standard cannot provide "right" UFLS program for all areas

  Response: A continent-wide standard can provide appropriate reliability requirements for most areas since most areas already have programs in the 25-30 percent of load range. A regional variance may be proposed if a regional or sub-regional UFLS program substantially exceeding this range cannot be made to comply with the continent-wide performance characteristics. Input from MRO has been considered in replacing the discrete points in Draft #2 with curves in Draft #3. Please see R3 and Attachments 1 and 2.

- The continent wide standard should check if the assessment steps have been completed (a “pass/fail” approach)

  Response: The SDT believes that a check list approach constitutes a fill-in-the-blank standard similar to the existing PRC-006 which FERC did not approve. The SDT believes that a check list approach will not address the FERC concern that fill-in-the-blank standards have the potential to undermine uniformity. The SDT believes that requiring an assessment to show that compliance with certain measures of reliability (i.e., performance characteristics) has been achieved is necessary. The SDT does not believe that reliability can be assured if the standard is limited only to checking to see whether certain steps have been followed in conducting an UFLS assessment.

- The NERC regions have always had the organizational structure to bring all of these experts together, and I doubt the concept of having a group of Planning Coordinators will be as effective at getting the subject matter experts involved

  Response: In fulfilling the Planning Coordinator function the Planning Coordinators need to coordinate with the “experts” such as relay engineers, Transmission Planners, Distribution Providers among others. The Standard Drafting Team does not see an alternate approach to assigning responsibility to the Planning Coordinator. Furthermore, FERC Order 672 indicates that requirements should be assigned to users, owners, and operators of the bulk electric system and while the SDT agrees that the Regional Entities should be involved, the SDT can only assign the responsibility to the Planning Coordinator (a user, owner, operator). The SDT feels that it has not precluded the involvement of the Regional Entity in the process nor precluded the Planning Coordinator(s) from electing to use their regional standards development process as an open to all entities and inclusive process to establish the program.

- “Real world” factors also should be considered when designing the program – studies aren’t sufficient

  Response: The SDT agrees that real world factors should be considering when designing and assessing a UFLS program; however, the SDT believes the appropriate method for considering the factors is to model them in studies. The SDT is not aware how else the effects of such real world factors as variation in governing response and controls that override governing response can be evaluated.

- PRC-006 and PRC-024 are circumventing the needed analytical process and are drawing conclusions about what is appropriate before the study work is performed. These standards provide no technical justification for the proposed measures. As written, these standards will encourage smaller load shedding programs, and if that happens, the result will be that portions of the grid will have less of a safety net to rely upon when extreme events occur.

- Setting the performance characteristics before designing the programs is putting cart before the horse especially because size of the program should be a factor considered in determining any performance criteria

  Response: (to both comments immediately above): Clear and measurable reliability requirements need to be set. This goal cannot be accomplished if the reliability requirements are continually subject to being adjusted to accommodate study results. The SDT is confident that the draft UFLS standard will be found appropriate for the vast majority of North American systems. The fact remains that almost all existing North American UFLS programs fall within the 25-30 percent of load range. The SDT believes that what is behind the majority of the commenter’s comments is a concern over sub-regional UFLS programs that need to be substantially more than 25 percent. A regional variance may be proposed if a substantially larger sub-regional UFLS program cannot be made to comply with the continent-wide performance characteristics for load-generation imbalances up to 25 percent. Input from MRO has been considered in replacing the discrete points in Draft #2 with curves in Draft #3. Please see R3 and Attachments 1 and 2 in Draft #3.

- There is no requirement to assess load shedding needs – major topology changes should be considered when performing an assessment

  Response: The draft standard requires the identification of islands for study in Requirements R1 and R2 of Draft #3. This identification should consider topology changes. The study of such islands should reveal the load shedding needs in terms of percent of load to shed.

- Any party (utility, group, region, etc) should not be forced to shed more than the minimum called for in the Standard, but we should let them shed more load when there is an advantage to doing this

  Response: The SDT notes that the proposed standard does not specify the amount of load to be shed. Specifying such details of the programs is left to the Planning Coordinators in each region. The SDT agrees that entities should be allowed to shed more load than required when advantageous provided that shedding more load does not result in an

overfrequency condition that adversely impacts reliability.

- Both voltage and frequency are highly subjective and are not really a good way to indicate if a load shedding program is going to get the job done.

  Response: The SDT understands that frequency performance is subject to factors that are often uncertain or variable, such as aggregate inertia, aggregate governing response, turbine power versus frequency, and the effect of load shedding on system voltage and the secondary effect of that voltage on remaining load, etc. Nonetheless, a UFLS program must be set up to operate on frequency settings, generator off-nominal frequency durations defined in terms of frequency level must be respected, and system load is a function of only the voltage and frequency applied to it. The SDT believes that these quantities are the only quantities available for assessing the performance of an underfrequency load shedding and that the only means of evaluating these quantities is through dynamic simulations.

- The standard is driving towards lowest common denominator - Somewhere the NERC UFLS standards drafting team also concluded that "UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics". Programs which shed different amounts of load will inherently have different performance characteristics, and work over a different range of overloads. By setting frequency based performance criteria these two standards are definitely forcing things towards the lowest common denominator as the proposed "measures" can only be met by a smaller load shedding program.

  Response: The SDT disagrees that the draft standard would result in least common denominator reliability. Again, the SDT has determined that the approach that is least intrusive on the flexibility to set UFLS design parameters within a region, but that addresses the need for inter-regional coordination, is to establish continent-wide performance characteristics as are now in the draft standard. The draft standard would not restrict regions from having programs larger than 25-30 percent of load because such programs are not precluded by the proposed standard, and a regional variance may be proposed should such larger programs encounter difficulties in complying with the performance characteristics up to the 25 percent load-generation imbalance level.

- This reliability standard writing process should not replace engineering judgment

  Response: Reliability standards must establish clear and measurable requirements. The SDT does not intend to preclude use of engineering judgment in meeting the requirements; however, engineering judgment cannot be a substitute for clear and measurable requirements. The SDT believes a balance has been achieved in the proposed standard between imposing clear and measurable continent-wide requirements versus permitting flexibility for engineering judgment within each region.

- I think it makes perfect sense to "measure" if we are fulfilling the basic aspects of load shedding obligations. The "measure" would be "have you done activities x, y, z?". Instead we would focus on the big picture, which is to make sure we have a reasonably effective safety net in place. The "measures" could become simple pass/fail checks to see if we have covered the basics of implementing an appropriate UFLS program. I suggest that we keep it really simple. It will be easy to check on things like: 1) has an appropriate program been designed which satisfies a checklist of items that have to be considered such as coordination with generation protection, 2) has the program been implemented, 3) has the program been periodically reviewed, 4) have any changes that came about from the review processes been implemented in a timely fashion, and so forth

  Response: The SDT believes that a check list approach constitutes a fill-in-the-blank standard similar to the existing PRC-006 which FERC did not approve. The SDT believes that a check list approach will not address the FERC concern that fill-in-the-blank standards have the potential to undermine uniformity. The SDT believes that requiring an assessment to show that compliance with certain measures of reliability (i.e., performance characteristics) has been achieved is also necessary. The SDT does not believe that reliability can be assured if the standard is limited only to checking to see whether certain steps have been followed in conducting an UFLS assessment.

- R1- a group of planning coordinators is not going to be the equivalent of the type of broad based participation we have historically achieved through the NERC Regional via the existing committee structure.

  Response: In fulfilling the Planning Coordinator function the Planning Coordinators need to coordinate with the "experts" such as relay engineers, Transmission Planners, Distribution Providers among others. The Standard Drafting Team does not see an alternate approach to assigning responsibility to the Planning Coordinator. Furthermore, FERC Order 672 indicates that requirements should be assigned to users, owners, operators of the bulk electric system and while the drafting team agrees that the Regional Entities should be involved, the drafting team assigned the

responsibility to the Planning Coordinator (a user, owner, operator). The drafting team feels that it has not precluded the involvement of the Regional Entity in the process nor precluded the Planning Coordinator(s) from electing to use their regional standards development process as an open to all entities and inclusive process to establish the program.

- R2-stresses consistent application across the region, and I would argue that only the final analysis of the system will tell you if this makes sense. There may be subregions which have different needs. In MRO, the Canadian systems have different needs than the US portion of MRO.

  Response: The SDT agrees that sub-regions within a region may have specific needs and has deleted the word "consistent" from this requirement to allow unique UFLS program parameters for a sub-region as part of the program developed by the Planning Coordinators within a region. However, if that sub-region is identified as being part of any other island that forms the basis for the UFLS program design (now Requirement R2), then the sub-regional UFLS program parameters must be coordinated with UFLS program parameters established for the remainder of the region to ensure the performance characteristics are met for all islands. A regional variance may be proposed if a sub-regional UFLS program cannot be made to comply with the continent-wide performance characteristics but support the reliability intent in an alternate fashion. Input from MRO has been considered in replacing the discrete points in Draft #2 with curves in Draft #3. Please see R3 and Attachments 1 and 2 in Draft #3.

- R3- this says we need criteria on how to select islands. It strikes me as odd that we need "criteria" on how to reach a conclusion. Shouldn't this just say that analysis shall consider possible system break up patterns that may form islands?

  Response: "Shall consider" is not definitive enough language to measure compliance against; "…shall develop criteria…" is definitive. In some regions, there may not be any "break up patterns." Thus, it is necessary to have some selection criteria as the requirement to identify islands that will be used to design the UFLS program.

- R4-I agree that coordination with neighboring regions is required, but I do not know how to resolve differences of opinion between regions. Are we trying to reach a consensus between regions, or just trying to share information and to create a forum for discussion? Obviously where breakups cause islands that straddle different NERC regions, we need to jointly evaluate that island. Even if this coordination is only to share information, it still allows everyone to learn from each other and is going to be quite valuable.

  Response: Thank you for your comment. Please see Question 6 on the comment form. R4 has been removed and a new Requirement, R4, has been added. We expect that a process for resolving differences of opinion between the Planning Coordinators will be necessary because their compliance with R4 will depend on it.

- R5 - Propose a wording change, I would rather say something like: "…shall identify islanding patterns that can be used as a basis for designing an UFLS program. This shall consider:" R5-is about identifying islands. I think it is the exact wording of this section that bothers me although I agree with the intent. I prefer to focus on break points that may lead to islands.

  Response: The SDT believes the language of the standard provides a clear requirement against which compliance can be measured; seeing the commenter agrees with its intent, no changes have been made.

- R7-is about the need to do periodic assessments. I agree we need a periodic assessment of some sort. Full blown studies on the other hand are seldom required unless some inherent flaw in an existing program is identified and we need to start with a fresh look at everything. I do not agree with meeting the performance characteristics in R6. We should meet performance characteristics which are defined as a result of the load shedding study process, and not just something that is tossed out up front.

  Response: The standard requires dynamic simulations to back up the required periodic UFLS assessments. The SDT has confidence that any inherent flaws in an existing program are more likely to be discovered in this manner than by any other approach. Reliability requirements should not continually be subject to being modified to accommodate study results.

- I think there are other ways to assess the risk of having units trip off early than just running simulations. This almost implies we have to use full stability cases as our only analytical method. Let engineers figure out how to study the problems using whatever tools, methods, and calculations they feel are appropriate.

  Response: The standard requires dynamic simulations in the assessments because the reliability risk of early tripping units can be adequately assessed in this manner. The SDT is not confident that analytical methods that do not involve

dynamic simulations can do this.

- If we require some assessment of load shedding “need”, then generation which drops off early can be evaluated in terms of how it affects the “needs” assessment, or we can demonstrate how loss of such generation affects programs in a general sense.

  Response: The SDT agrees. Load shedding needs should become apparent during the course of performing dynamic simulations for the assessment of island(s) identified in R5 (now R2).

- R-8 shouldn’t this database/modeling type of information be compiled as part of the regional model building process? NERC regions do this type of thing today, why is this group of Planning Coordinators getting involved in this. We use the NERC regions to do our coordinating activities, so why depart from what works? I need to understand the reasoning behind this before I can comment further.

  Response: At this point, UFLS data is not required to be included in regional and ERAG / MMWG model building. UFLS data is for a specialized field of study distinct from the general dynamic simulation data collected under MOD-012.

- R-9 appears to say that everyone shall trip load in accordance with the UFLS program. I agree with the intent.

  Response: Thank you for your support.

22) Question 8 Comments:

1.0 Introduction

After reviewing PRC-006 and PRC-024, I have to conclude that both are unsound. The general approach of trying to define a performance envelope up front before tradeoffs can be evaluated in the design work is going to be a problem. These standards really do not encourage the right thing, which is to ensure we have the right UFLS program in place to meet the needs of a given area. The “measures” are inherently subjective, and really do not measure if we have created the right “safety net”. I go into considerable detail to explain my concerns, but basically in the design phase we need to make compromises between mutually exclusive objectives. Therefore we need to stay away from trying to micromanage the design process at the Standards level. Tradeoffs affecting performance will always be involved and I do not think the standard needs to get involved in exactly how we reach a conclusion about what needs to be done. I think the standard should just focus on making sure we put the plans into effect, and that we implement the load shedding program. We should leave all of the performance issues to a work group that does the actual design and analysis. This is basically operating study type of work to create a remedial action scheme which responds to abnormal system conditions. My conclusion is that we need a different type of “measure” for the UFLS standard and that the generation off-nominal frequency protection related criteria in PRC-024 should be eliminated completely and that it should not be part of any NERC standard. PRC-024 is trying to make the compromise about what is an acceptable tradeoff for setting generation off-nominal frequency protection before the required study work is even started. It makes more sense to have a “measure” for UFLS which focuses on fulfilling the various activities such as design, implementation, and review, as the end result is what is important to ensure reliability. I envision this would be more of a pass/fail, have you performed these activities or not, type of assessment. I know this is a controversial statement, but I believe the following discussion will explain how I arrived at this conclusion.

1.1 My UFLS background

Before I comment on technical issues, I would like to provide background information. This is to explain why I hold such strong opinions on the subject of UFLS, and to show my involvement and commitment to developing appropriate regional UFLS programs. I hope this gives some credibility to my statements. I have a unique “hands on” work experience. This gives me considerable insight into this subject and a different perspective. I have about 20 years of experience with UFLS issues, have dug deep into the subject, have read all the technical materials I could find, and so forth. I spent several man years on this subject although my primary job function involves power system analysis, mostly operating studies (power flow and stability studies and so forth). My initial involvement in UFLS was an offshoot of disturbance analysis. This involvement with UFLS expanded into the area of assessing regional needs and in doing the technical work to develop a new UFLS program from the ground up which better fit the needs of different geographic regions. This was the big picture type of work with lots of things to consider. My background which is relevant to this area of investigation includes:

* 29 years of experience doing system studies (power flow, transient stability, operating study work, modeling issues, disturbance analysis, etc.)

* From 1987 to 1990 worked almost full time on the Colorado/Wyoming Off-Nominal Frequency Program design and study report (a regional load shedding and generation off-nominal frequency protection coordination effort tailored to the needs of the area, and which coordinated the needs to two islands, one a subset of the other). I was chairman of one of two technical work

groups created by the executive committee, and did a significant amount of the analytical work and report writing.

* 1996-1997, I worked on the WSCC UFLS program design and study report as one of five authors. This program is presently the WECC program and was strongly influenced by how the Colorado/Wyoming program was developed.

* 2001, I performed a review of the MAPP UFLS program on behalf of MAPP, and concluded that MAPP needed to develop a new UFLS program to address overfrequency and generation off-nominal frequency protection concerns.

* 2006-2007, I was chairman of the MRO UFLS Task Force which designed a new UFLS program and generation off-nominal frequency protection requirement for MRO. This was basically the follow up to the MAPP work that stalled out in 2001. Implementation has been put on hold until the NERC UFLS standards writing process has concluded.

* I have had the benefit of collaborating with many other engineers, of varied backgrounds, on the subject of UFLS. I have been exposed to many different aspects of the problem and to different viewpoints. My perspective is based on information I have gathered as it pertains to system planning and operation, relaying, control area type of issues, power plant issues, and so forth.

I was once told that "sometimes things seem simple only because we don't usually have the time to learn the complexities". This is certainly true of UFLS issues. This standards drafting process has led to certain initial conclusions that set the direction of how the UFLS standard is being drafted. I have to point out that things are not nearly as simple as they may appear at first glance, and we are jumping to the wrong conclusions, and that is steering this process in the wrong direction. In order to best explain my concerns with how this UFLS standard is being written, I need to cover some of the basics to provide a context.

1.2 The big picture: what are we trying to accomplish by shedding load?

The simple answer is we want to use load shedding as a safety net. The objective is to prevent a blackout following an islanding event that creates an imbalance between load and generation. We want the program to force quick frequency recovery so that we can better coordinate with generation off-nominal frequency needs. We want to make sure that our program has no fatal flaws that are going to make things worse, and hopefully we can try to make this program as robust and foolproof as possible.

1.3 Who should design UFLS?

The design details need to be resolved through a technical study process involving individuals with the skills to do this type of analysis, or who are willing to spend considerable time to learn the skills. Historically this has been accomplished by forming appropriate study groups. Such groups usually include individuals with varied backgrounds which may be relevant to dealing with the different aspects of off-nominal frequency issues. The NERC regions have always had the organizational structure to bring all of these experts together, and I doubt the concept of having a group of Planning Coordinators will be as effective at getting the subject matter experts involved.

1.4 Analytical approaches and modeling limitations

First of all, there is no perfect tool for studying load shedding and performance is highly subjective. The question is, what performance, and for what conditions and assumptions? We have to keep this in mind before jumping to conclusions about what kind of performance characteristic we can meet.

Trying to establish the UFLS performance characteristic up front and then designing the rest of the UFLS program afterwards is equivalent to saying we know what our protection needs are and what the resulting system performance is going to look like before we do any kind of analysis at all. This is unrealistic. The one factor which is the most significant is the size of the UFLS program. Larger programs have inherently different performance characteristics than small programs. More compromises have to be accepted to make larger programs work. NERC Regions typically set a minimum criteria for load shedding, but higher levels are sometimes needed and are typically allowed. The amount of load presently being shed in different areas varies from about 25% to 60% or more.

Modeling must involve some form of dynamic simulation which captures the salient features. Underfrequency relay application guides suggest use of a simple equivalent inertia model which captures frequency decay dynamics. I have found this approach extremely useful and insightful. This approach is good for rapid prototyping and generalizing trends, evaluating performance over a range of overloads, evaluating sensitivities, etc. The weakness of this approach is it does not include effects of voltage changes and usually ignores governor action (in MRO UFLS work, we added a governor model as part of the sensitivity work, but designed the program to work even if we get no net governor type of response to an underfrequency event). The “Equivalent Inertia” approach is essentially use of a one bus stability case with voltage held at unity, which models the inertial response of a full system.

Full stability cases are more useful for looking at a very specific scenario (one overload level, a historical event, etc.). Stability cases are also useful in addressing voltage transients and identifying possible system break points. The usefulness of a full stability case for the study of load shedding is often overestimated. In reality, too much detail is not always helpful in sorting out the general trends. Stability cases give a very specific answer but can fail to give the needed insight about how things work "in general" and it can take significant time to modify cases so they are useful for this type of analysis. The level of modeling needed for typical transient stability studies is somewhat different than what might be needed for a load shedding study, so do not expect that stability cases will have all of the modeling details needed for load shedding studies.

The user has to be aware of what each dynamic modeling approach represents, and what the modeling limitations are. Even full stability cases do not model some of the processes which have an effect on a load shedding event and consequently results have to be carefully interpreted (for example, stability cases do not model generating plant boiler dynamics and emergency overspeed controls which protect for full load rejection, but which operate on large partial overloads). The way islands are created in the simulation can affect results. For instance, opening all lines at the same instant to form an island is a typical modeling approach that has nothing to do with how islands really form. This approach to creating an island will affect the final result to some extent, but we generally have no better option.

We also need to stop once and a while and consider the real world issues to try and make things as fail safe as possible. There is more to UFLS design than just running studies.

The point is that study work results are inherently approximate, and much more subjective than most realize. Simulations need to be interpreted with a good deal of common sense and a good understanding of system dynamics, and a clear idea of what all the qualifying simulation assumptions are. Hopefully this standard will stay away from prescribing any particular modeling or analytical approach. Let planners use the engineering tools they have as they see fit, and let them decide on the tradeoffs we have to accept to make this work.

1.5 UFLS design work, conflicting requirements, and uncertainty

UFLS program design and performance details can only be worked out through a systematic study work process that considers all of the relevant details, the conflicting requirements, and as much of the inherent uncertainty involved as is possible to consider. Despite the complexity, I believe we can design a good UFLS program for a given region if we are systematic and try to deal with all the issues as best as possible by applying good engineering methods and good judgment. Once we lay out all the details, we have an optimization problem, and have to consider the options available and the tradeoffs. Some of the final program details will probably end up being decided according to a judgment call. However, I do not believe that we can set performance standards first and then expect the engineers to magically make this work. Almost everything to do with UFLS has to be based upon study work and must have a solid technical justification.

The design goal is to develop an UFLS program which has a high probability of preventing system collapse following an islanding event. This sounds simple so far, but a little investigation will show the problem we are trying to deal with is complex and poorly defined. We are guessing at what might happen and are trying to hedge our bets in the face of considerable uncertainty. The deeper the investigation goes, the more we become aware of the conflicting requirements. For instance, the things we need to do to limit the minimum frequency, to limit the maximum frequency, to ensure good relay coordination, and to maximize the size of the UFLS program all conflict with each other…to solve one problem we impact a different objective.

Many factors which affect real world performance are outside of the control of the parties doing load shedding. These factors are: dynamic characteristics of load, system energy stored in rotating generation via the flywheel effect (this is the inertia, and it relates to dispatch), units which are unresponsive to governor action, boiler dynamics, power-load controllers which can over power governors and force units back to the original schedule, gas turbines which inherently drop power as frequency drops, wind generation which essentially provides no inertia and is highly unpredictable, unexpected random events, etc. To complicate the analysis, different parts of North America will have to address factors that are unique to their own local areas.

We want to keep "real world" complications in mind as we do our studies, and it is even reasonable to anticipate what system operators will have to do next if load shedding fails to work as desired. Historical events show this happens, and if we are lucky frequencies will stall out close enough to 60 Hz that operator action can be initiated to restore frequency (this has implications concerning why it is a really bad idea to set generation protection time delays too short for frequencies between 59 Hz and 61 Hz).

Also consider that we are just making educated guesses about what islands may form in real life. Some islands are easy to identify and predictable, but that is not always the case. Major breakups seem to occur following a sequence of events which are far beyond anything covered by typical criteria, and these events are usually nothing we would have ever dreamed up. Often the final island is not what we anticipated.

At this point let's assume we know what our island should be, what the maximum overload for this island will be, and that we

have some idea of general performance objectives. As we go into study mode we find that many of the factors which affect results are difficult to pin down. This includes the assumptions used for load damping, governor response, and the energy stored in rotating units (the inertia). The term “typical data” reflects a rather wide range of these parameters. In developing the MRO program we dealt with this uncertainty by using the simplified equivalent inertia model and then varying all of these parameters over a fairly wide range as we also considered a range of potential overloads. This is much more than is typically done, and this type of sensitivity analysis would have been extremely difficult, if not impossible, to perform with a full stability case.

In the design phase we want to work though all of the interrelated issues, such as achieving coordination with generation off-nominal frequency protection. To do this right, we have to design a load shedding program which gives the best frequency recovery (subject to all the other constraints), and then see how much time is spent below 60 Hz in various frequency bands so that we can propose generation protection settings with delays with some margin over our worst case frequency recovery times. We also need to know something about actual generation off-nominal frequency capabilities to further judge the appropriateness of the suggested protection settings.

We want to make sure this safety net is well designed and that it has no obvious flaws. Preferably, we want to anticipate what could go wrong so that we can try to avoid as many problems as possible and alter the design accordingly. Then work has to iterate towards a best compromise solution.

2.0 Critique of PRC-006

Although the intent of this write up is to discuss PRC-006, I also have to discuss PRC-024 in some detail since both standards go hand in hand. Load shedding and generation protection are interrelated. Both parts have to be addressed together in any discussion of UFLS issues. It is unfortunate the standards drafting teams broke things down into two different standards like this. Generation off-nominal frequency protection is inherently part of UFLS programs, and has to be assessed in this context.

2.1 UFLS standards need to be technically sound.

I empathize with the standards drafting team and know the difficulty of their task better than most. However, I am not satisfied with the NERC UFLS standard PRC-006 or the generation protection settings suggested in PRC-024. I find this new PRC-006 UFLS standard and the companion PRC-024 generator off-nominal frequency standard to be unsound. These standards are circumventing the needed analytical process and are drawing conclusions about what is appropriate before the study work is performed. These standards provide no technical justification for the proposed measures. As written, these standards will encourage smaller load shedding programs, and if that happens, the result will be that portions of the grid will have less of a safety net to rely upon when extreme events occur.

2.2 There is no requirement to assess load shedding needs

My observation is that a minimum load shedding requirement of 25% to 30% of system load will serve the needs of most of the system. That is my personal judgment, based on previous study work experience. I also know we can design fairly well behaved programs which shed 30% of load, and my personal bias is to shed more than to shed less. However the 25% load shedding used in the East was based on the same type of analytical process as I would go through, and they felt this level was a better fit for the tradeoffs involved. UFLS design involves these types of judgment calls. However, it seems odd that this standard does not require any kind of assessment to define the size of the imbalance we may have to deal with. This means we are not requiring anyone to know their actual load shedding needs. Perhaps that is implied by having “groups” do the UFLS study work. The load shedding needs are the first thing I would want to know, and to get at this information we have to evaluate possible system breakup patterns and possible load and generation scenarios to see what the imbalance might be. The purpose of such a review would be to see how much coverage the 25% load shedding requirement gives, and to estimate what might be a more appropriate load shedding target level. This type of analysis does not have to be perfect; we just need to know general magnitudes and make sure the involved parties feel their own needs are being satisfied. I use the phrase “target level” in the sense that once study work is performed we may have to consider a different size load shedding program to achieve over all coordination requirements. Everything is a series of tradeoffs. If we set performance criteria too tight, we could easily find that all we have left to work with to meet the criteria is to put in a smaller program, and then we will only meet criteria over this smaller range of coverage.

2.3 Higher load shedding levels should be encouraged if it makes sense

While we do not believe that any party (utility, group, region, etc) should be forced to shed more than the minimum called for in the Standard, we believe we should let them shed more load when there is an advantage to doing this. This will be the exception, but some areas, such as parts of Canada, are obviously prone to islanding and these areas often have high load shedding needs. Some areas shed 60% of system load, or perhaps more. Historically, UFLS standards have been minimum standards which tell utilities they must shed at least a certain amount of load. Regional programs allowed or even encouraged utilities to shed more load when it made sense. It seems obvious that this intent is still there, but the problem is that the “measures” chosen for this standard actually discourage this.

2.4 Frequency is subjective, and should not be a “compliance measure”

PRC-006 uses frequency and voltage as “measures” to ensure UFLS programs satisfy reliability objectives. I believe these are both inappropriate “measures”. Both voltage and frequency are highly subjective and are not really a good way to indicate if a load shedding program is going to get the job done.

Let’s review the basics: 1) frequency drops following loss of generation or import with an initial rate of change of frequency defined by the size of the overload and the system inertia, 2) since turbine power can generally be assumed to be constant, this frequency drop increases generator torque as torque=power/speed, 3) load torque drops according to the load damping characteristic, and 4) we eventually reach equilibrium at a new lower frequency where once again Generation = Load at the new synchronous frequency. (A footnote: turbine power is not always constant during a frequency decline, combustion turbines have thermal limits requiring the power output to be lowered as frequency drops, causing a further drop in system frequency. Governor response on these units will only be momentary before thermal controls take over.)

Now let’s consider how these variables affect our performance “measures”. For a given overload, final frequency is a direct function of the load dynamic characteristics which are not precisely known. We know the damping constant used in models is in the range of 1 to 2, and anything in that range is “typical”. Low damping will give the lowest frequency and highest frequency deviations. The equivalent system based inertia H = sum of MW-sec of online units/total Pgen, is a function of different unit dispatch scenarios. For a given overload, high inertia gives slower rates of frequency change, better relay coordination, a higher minimum frequency, and slower frequency recovery. Small inertia gives high rates of frequency change, lower minimum frequencies, relay coordination problems and possible overshedding.

With the wide range of “valid assumptions” to choose from, folks can essentially pick the off-nominal frequency results they want to show for compliance purposes, and if results of a large program don’t look good enough, they can switch to a smaller program so that it satisfies the “measure”. Choosing modeling assumptions is not “gaming”, it is standard engineering practice, but a single set of assumptions does not tell the full story. I would rather have measures which encourage folks to look for potential problems instead of measures which punish them for finding such problems. I would also like to see the measures encourage larger UFLS programs when that meets some identified need.

To further complicate matters; let’s compare a large UFLS program (sheds 45% to 60% or so) with a small program (sheds 25% of load). Let’s assume they both have 5 stages of load shedding. Over the range covered by the small program, it will work in a more refined manner than the larger program as it uses smaller load blocks. For overloads between the sizes of the two programs, only the larger program will work. So how should performance be judged?

There is a reason I chose the same number of load shedding blocks in this example, and it is worth digressing for a moment to explain. As a practical matter, UFLS programs can only make use of 5 or 6 high speed load shedding blocks while still achieving good relay coordination and while also keeping the minimum frequency from dropping too low. This is not a hard and fast rule, but it is what I have seen in my study work. This is an effect related to inherent time delays introduced by relaying detection times and breaker operating times, and the frequency spacing needed between relays to achieve relay coordination. Of course if we are willing to toss out relay coordination we can improve the underfrequency response at the expense of creating overfrequency problems which then have to be hammered back by automatic load restoration or the equivalent (for instance, Manitoba Hydro can drop power coming in on DC lines to balance load with generation but that is a very unique situation).

2.5 Voltage is subjective, and should not be a “compliance measure”

Overall, I am more concerned with the magnitude of the voltage out at the load rather than volts/Hz issues at the generator. The volts/Hz issues are already well covered by IEEE/ANSI standards, and this is difficult to model since exciter/voltage regulator models typically do not include a volts/Hz function, so the automatic reduction of the generator terminal voltage which occurs in real life does not show up in simulations. During load shedding the generators will be pulling the voltage down anyway. My understanding is that volts/Hz issues are less restrictive than other underfrequency concerns/factors. This would be something we need to look at if we allow frequencies to drop to 57 Hz or less. (Unit terminal voltage is controlled by the voltage regulator and outside of the transient time frame, we can assume the steady state voltage will be limited to 1.05 pu to .95 pu, so 1.10 v/Hz gives problems in the range of 60*1.05/1.1=57.27 Hz to 60*.95/1.1=51.8 Hz.) In addition, units are only at risk if this voltage regulator function fails, or if units are in manual voltage control. In that case the backup volts/Hz relaying will trip a unit. I am not too worried about voltage regulators failing and do not consider volts/Hz as a major risk factor. Usually volts/Hz is not given too much attention when designing UFLS programs. I am not aware of any of the existing UFLS standards having any volts/Hz criteria, but perhaps I am mistaken. I suggest the volts/Hz requirement be removed from PRC-006 because it really does not add anything which is not already covered elsewhere.

2.6 Overvoltage as a source of additional uncertainty

As load is shed we can get overvoltages out at the load which effectively increases system load. To some extent this voltage

related load increase offsets the benefit of load shedding. Voltage control issues during load shedding/system break up are extremely difficult to assess. Voltage changes are a function of changes to VAR supply/consumption, as well as inversely proportional to system strength (i.e. fault MVA magnitude). System breakups and associated loss of generation can weaken the system and make voltage control much more difficult to manage. There is a general recognition that some capacitors need to be shed with load, but such details have to be worked out and refined at the local utility level as part of the load shedding implementation phase. I do not have a good idea of what is “the best that we can do”. I imagine it will vary with disturbance. I am not sure how this should be handled in the standards drafting process. I want to create an awareness of the problem so that folks give this some attention, and apply good common sense, but I do not want to turn this into any kind of “measure”. This is more of a bottom up type of analysis where very specific local detail has to be considered, where the rest of the UFLS conceptual work is the top down, big picture stuff where we do not need to address such specific local details. I am confident that utilities will do the right thing once set on the right course, and these types of details can be reviewed in the subsequent periodic UFLS assessments and things tweaked if needed. I just don’t know how to make this process any better than this. We have to be careful that we do not try to micromanage this difficult task.

The MRO UFLS effort tried to anticipate as much complication as possible, but we could not cover all of the inherent uncertainty involved. No one could. The main source of uncertainty we could not deal with is how potential overvoltage’s may increase load and decrease the effectiveness of the load shedding program. This gave us additional justification for using a "no net governor response" scenario for evaluating coordination between load shedding and generator protection (this voltage uncertainty is not the only reason for using a no governor assumption: basically units that are base loaded cannot respond to underfrequency, power/load controllers may override governor action after a short time delay, combustion turbine thermal limits will quickly override their governor action with power dropping off faster than the frequency decline, wind generation may drop off and would not have a governor anyway, and so forth; the bottom line is that we do not know what level of net governor type of action we can count on, and what little we get may be offset by increases in voltage).

2.7 PRC-006 and PRC-024 are forcing UFLS programs to the least common denominator

PRC-024 and PRC-006 both fail to satisfy a comment made in the NERC UFLS unofficial comment form which indicates the UFLS standard is supposed to provide an appropriate level of reliability, not the least common denominator. Somewhere the NERC UFLS standards drafting team also concluded that “UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics”. Programs which shed different amounts of load will inherently have different performance characteristics, and work over a different range of overloads. By setting frequency based performance criteria these two standards are definitely forcing things towards the lowest common denominator as the proposed “measures” can only be met by a smaller load shedding program. The PRC-006 UFLS standard and companion PRC-024 establish tightly defined performance characteristics which at best will just barely work for a 30% load shedding level. Perhaps I should be more careful and say it works for a 30% load shedding level for a range of assumptions, but not for all of the conditions/modeling assumptions that we looked at in the MRO study. Those settings certainly do not encourage a robust UFLS program.

This “one size fits all performance envelope” approach only works if we use the worst case (largest UFLS program) as a basis for the performance envelope. We can characterize these larger load shedding programs as having to accept more tradeoffs. The minimum frequency will be lower, the maximum frequency will be higher, larger load blocks will have to be shed making things more drastic, and the programs are likely to be more susceptible to relay coordination problems (due to the high rates of frequency decline associated with the large imbalances). What you get for these tradeoffs is a bigger safety net.

The generation coordination part of UFLS analysis should be addressed directly in PRC-006 as something that needs attention, but the specific details such as those presented in PRC-024 need to be worked out at the UFLS working group level in coordination with the study process that designs the load shedding program. This type of information is not appropriate for NERC standards. The off-nominal frequency limits in PRC-024 should never have been created and should be eliminated. PRC-024 is poorly thought out and is going to do much more harm than good.

Setting generation protection up front before casework is run is putting the cart before the horse. This is an attempt to micromanage the UFLS analytical process without having a full view of the big picture. It just represents someone’s judgment call concerning what is appropriate. It does not accurately reflect generation capabilities and no technical basis was provided to justify the “measures” in the standard. In my opinion PRC-024 is seriously flawed and actually is a serious threat to reliability. It also conflicts with the new MRO UFLS program we developed, and if other regions did the type of analysis that we did, they would probably find this causes problems for them as well. (Most UFLS programs do not go to as great of lengths as we did to look for potential problems over the full range of overloads covered by the program.)

I am well aware of generation off-nominal frequency issues and concerns, I have had my eye on this for 20 years. In the MRO UFLS study we did all that we could to minimize the off-nominal frequency exposure to generation, even going to the point of designing the load shedding program as the first line of defense for generation. This is achieved by designing the UFLS program to force quick frequency recovery even if we get no net governor action. This is achieved by having small blocks of load shed on delay that only trip if frequency recovery is sluggish. The point to make here is that the PRC-024 standards drafting group is not

the appropriate group to be deciding on what tradeoffs are appropriate for coordinating load shedding with generation protection requirements, and they are ignoring some important “real world” consequences. Some of what is in PRC-024, if implemented, would be catastrophic for the grid.

2.8 Overfrequency issues

The diagram from PRC-024-1 suggests that overfrequency tripping of generation is going to be allowed in similar fashion to how underfrequency tripping of generation is applied. Extreme caution is needed. If we add relays to instantly trip generation according to the overfrequency part of PRC-024, we will have multiple units tripping at the same time and we will cause a blackout. I would call this a really big fatal flaw.

Units self protect on overspeed and we do not have to add additional overfrequency tripping relays unless this is a planned activity used to balance load and generation.

It is important to have some understanding of overspeed issues and related controls, so I need to take a moment to cover this subject. In addition to the normal speed regulating governor, all power plants already have internal emergency overspeed controls to deal with full load rejection (loss of all lines out of the plant with turbine running flat out). These controls also activate on partial load rejections (overfrequency during islanding). These controls can have many names: emergency or preemergency governor, overspeed controls, load rejection controls, trip anticipators, or something similar. We do not want to be modifying these controls and their settings, but we need to understand how they operate. These controls vary at each plant so the following discussion has to use generalities to make my point. I am most familiar with controls on steam plants so this discussion applies to that type of generation. Generally these emergency overspeed controls try to limit peak speed to something below 110% by closing all turbine valves, and if this fails, the unit is tripped to prevent mechanical damage. To limit peak speed, these controls have to start closing valves as units start to accelerate. These controls are applied a little differently at every plant, but have to act before things get out of control, so they generally activate between 61.2 Hz to 61.4 Hz on low inertia units (in this instance I am talking of the inertia constant in dynamics, H=MW-sec/Mbase of machine), and sometimes not until 62 Hz if unit inertia is high. These emergency overspeed controls are in addition to the normal governor, and are much more drastic and just slam all steam valves shut. These emergency overspeed controls are not modeled in stability cases and I bet that most planning engineers have never given them much thought. It seems we never see frequencies any higher than about 61.4 Hz following a breakup, while stability cases might indicate frequency should have gone much higher. These would be the controls responsible for that disconnect between the real world and the simulation world.

Outside of the inherent factory installed overspeed controls, we have to exercise great care and caution when applying additional relays to trip generation on overspeed. The purpose of such tripping would be to restore the balance between load and generation within an island. If this is done, we need to be aware of the risk involved. Because these load rejection controls slam valves shut, the system frequency is unlikely to get much higher than 61.4 Hz (for a system which is primarily coal fired) no matter how large the initial imbalance. (Most steam units that I have looked at activate around 61.2 Hz to 61.4 Hz, and at one time I looked at every unit in Colorado and Wyoming to get a feel for what is typical.) Once these controls activate, frequency is no longer a measure of the imbalance between load and generation. We cannot keep steam valves closed for too long, constraining all the steam with the boiler going full tilt, or else random unit trips will start to occur due to any number of internal plant problems. We do not know how much time we have to get valves back open before we are at risk of losing a unit. Someone estimated 15 seconds (I can’t say if this is right or wrong, but it sounds about right to me), and then internal plant problems will start to occur. Often we see that one plant trips first and this helps. That reduction in generation rebalances things for other units allowing steam valves to reopen. The random nature of what happens in response to overfrequency complicates any planned unit tripping actions to correct the imbalance. If the sum of planned and unplanned tripping is too much, we cycle into another underfrequency event. This illustrates why dedicated unit tripping on overspeed has to be considered carefully, and should only be applied as a method to rebalance load and generation, and not as overfrequency protection of the type we apply for underfrequency. If generation is tripped to correct overspeed in an island, it has to be done in small increments (equivalent to about 1 to 1.5 % of remaining load) and trip times have to be staggered. For the purpose of balancing generation with load, unit tripping should only be implemented on a few selected small units. The trip setting would have to set at frequencies no higher than something like 61Hz to 61.4 Hz, or else these relays may never pick up. Picking the right delay times is tricky and would have to be based on simulation results. In practice, it may make more sense to do automatic load restoration to rebalance. This is something that has to be studied on a case-by-case basis.

As a side note: in the MRO UFLS effort completed in 2007, we were very concerned about overfrequency. This led to changes from the MAPP program of shedding 3 blocks of 10% to a program shedding 5 blocks of 6% . We then focused on adding adequate spacing between relay settings to reduce the risk of overshedding under our worst case assumptions of large overload, low inertia, and low load damping. The compromise was we had to accept lower minimum frequencies.

2.9 We need realistic minimum frequency limits on generation that meet load shedding needs

I also have concerns with the chosen minimum frequency in PRC-024, and the time delays proposed at different frequencies.

Although the MRO UFLS Taskforce expects that under "typical conditions" that minimum frequency will be above 58 Hz, (for loss of generation/import of up to 30% of system load in the island), our worst case simulations indicate we could briefly dip below that, and we used our worst case results to set generation protection frequency settings and delays. In addition, our "equivalent inertia" modeling approach ignores machine to machine oscillations which might cause frequency at different locations to differ by .2 Hz or so as the system frequency rings down. For this reason, we chose 57.6 Hz as the point where instant tripping of generation is allowed. This is below our worst-case minimum frequency of 57.77 Hz (for a very low inertia, low damping, no governor scenario that is perhaps overly pessimistic). This instant trip setting for generation can also be justified in another way. Our design criteria set a target where we wanted the minimum average system frequency >= 58 Hz, and we seem to meet this for most conditions. This 58 Hz minimum frequency seen in our models then has to be adjusted by about - .2 Hz to account for machine to machine oscillations seen in the real system and not in our model, plus about .2 Hz margin to ensure good relay coordination. This takes us back to 57.6 Hz as the appropriate frequency for the instant trip setting on generator off-nominal frequency protection. Programs which shed more than 30% of load will need to relax generation protection and accept lower frequencies and longer time delays.

2.10 An example of coordination between load shedding and generation protection as performed in MRO UFLS study

In order to come up with the MRO generation protection settings we monitored time spent in frequency bands spaced .1 Hz apart and we consider the performance over the full range of coverage (0 to 30 % loss of generation) and considered a wide range of assumptions concerning system based inertia (H system base = total MW-sec stored in rotating mass divided by P gen) and a range of damping, in addition to a possible range of governor actions. We optimized the program to minimize time spent below 60 Hz while addressing all the other constraints we had to deal with. Once we knew the expected worst case times in each .1 Hz band below 60 Hz for the optimized program, we came up with the stair step type of generation frequency versus time delay settings that gave a reasonable fit to the expected worst-case time versus frequency information (plus some margin) with the fewest frequency bands. To fully understand what we did you will have to refer to the MRO UFLS report on the MRO website. The short version is that we ran 1000's of cases to arrive at our conclusions. What we came up with for generator underfrequency protection minimum time delays is what we need to ensure the load shedding has time to play out to restore frequency and to give some margin to ensure relay coordination. If we shorten the generation protection time delays and raise the frequency setting for the instant trip point, then there is a narrower range of conditions for which the UFLS program would be expected to work as intended. Our safety net becomes less robust, we make things less secure.

2.11 Load shedding can be used as the first line of defense when it comes to generation underfrequency protection

The MRO load shedding program is designed to be the first line of protection for the generators because it is designed to force frequency recovery even in the absence of governor action by having small blocks of load shed on delay to quickly bring us back towards 60 Hz when recovery is too slow.

2.12 Generation off-nominal frequency protection settings imply more risk than units may experience

Although there is a chance that frequency may be slow to recover as a worst case, most of the time it will recover much faster than the times we used for generation tripping coordination. The expected time spent below 60 Hz sort of takes on the form of a probability density function. This type of information gives a better idea of what units may be exposed to, and the real risk is less than what the generation protection settings may imply. Therefore, our approach was to coordinate generation off-nominal frequency protection to match the worst case frequency recovery times seen in our simulations after first doing everything possible to minimize underfrequency exposure to generators when designing the load shedding program. For the MRO region, the recommendations of the MRO UFLS report should take precedence over what is being proposed in PRC-024 and PRC-006.

2.13 UFLS programs which shed higher levels of load need less restrictive generation off-nominal frequency protection

In MRO, we recognize that the Canadian portion of MRO needs to shed more than 30% of connected load. The MRO UFLS report indicates that any program that needs to shed more than 30% of load will need to relax the MRO generator off nominal frequency time delay settings for generation and accept longer delays and lower minimum frequencies. This is an engineering reality. The Off-Nominal Frequency Capability Curve from PRC-024 does not give this kind of flexibility. Alternately, some improvement on minimum frequency can be realized by designing a program that oversheds but then the program will be prone to overspeed problems. This approach can get scary. Some improvement in coordinating with generation needs can be achieved by designing the UFLS program to start shedding at higher frequencies. This gives a corresponding improvement to the minimum frequency but this action often creates coordination problems with neighboring programs. On the other hand, sometimes you want one area to start shedding first to meet some specific objective. This is just another example of how every single facet of UFLS program design has to be carefully considered. In many ways, this is no different from any other type of planning or operating study work.

The bottom line is that this reliability standard writing process should not replace engineering judgment. Utilities need flexibility so they can make the necessary compromises after all things are considered. Making adjustments to generation protection frequency settings and associated time delays is most likely the best approach to ensure coordination with larger load shedding programs. We must give sufficient time for load shedding to act even if it means we need to accept some additional potential loss of life to generation for some hypothetical underfrequency event. I believe this is prudent and will not place undue

burden on generation.

2.14 The starting frequency of load shedding programs

In MRO we would have considered an UFLS program which starts to shed load at frequencies above 59.3 Hz (probably 59.5 Hz) if neighboring regions would have shown interest in doing the same. However that was not the case. All the programs in the region started at 59.3 Hz so we stuck with that. If we had increased the starting point to 59.5 Hz, we might have increased the risk of dropping load on power system swings where no load dropping is needed (if so, this would probably be isolated to a few buses), but we would have improve the minimum frequency and this helps larger load shedding programs meet coordination needs.

2.15 Turbine/Generator underfrequency capabilities

To talk about off-nominal frequency capabilities of turbine/ generators, I will once again have to generalize a bit. The continuous operating range for no accelerated loss of life is typically 60.5 Hz to 59.5 Hz. The frequency which requires an instant trip, for most generation (I will ignore combustion turbines for now), is below 57 Hz for steam, and as low as 56 Hz or lower for hydro. Steam turbines are more restrictive than hydro because of blade resonance issues and the result is that the time versus frequency limits are logarithmic with considerable operating time allowed just below 59.5 Hz and very little operating time is allowed at the lower frequencies. Limits are generally based on a theoretical “probable loss of life” after being subjected to some total time spent below 60 Hz over the life of the plant. This also fails to take into consideration that units get maintained and some issues are corrected before becoming problems. So we have to evaluate what fraction of this theoretical off-nominal frequency based accelerated loss of life needs to be used to respond to a rare and infrequent islanding event, but in the end this is a judgment call and is driven by what we have to accept to get the job done. Limits for combustion turbines seem to vary, with instant tripping suggested anywhere from about 57 Hz to 58.2 Hz. I know less about these than I do about other types of generation, but we learned what we could about these during the MRO UFLS study process. The group that did the last WECC UFLS review got quite involved in this area of investigation, and the MRO group benefited by consulting with the former chairman of that group. 20 years ago the combustion turbines were not showing up as a limiting factor, or we failed to notice the issues. I personally question the basis for the 58.2 Hz instant tripping point that is recommended for one make and model. It is hard for me to imagine that a very brief dip below 58.2 Hz is going to be a problem when considerable operating time above 58.2 Hz is allowed. This low “instant trip” frequency setting is out of line with historical industry practices and our industry has to encourage manufacturers to build equipment with better off-nominal frequency capability than this.

2.16 Don’t get too conservative with Generation off-nominal frequency protection settings

I feel that many times utilities try to get too conservative in how they want to set generation-off nominal frequency protection to the point where this may affect UFLS. If we set this too tight we might end up with a blackout. Black start plans are where the real off-nominal frequency loss of life can be chewed up. Generally such plans call for this protection to be disabled so that it does not interfere with restoring the system.

Another issue that I have heard several times as justification for using very conservative generator off-nominal frequency limits is that some folks are claiming their insurance sets underfrequency limits for their generation. Who is to say if the terms of the insurance coverage even makes any technical sense? This hardly sounds like a legitimate reliability issue. From my perspective, this seems at odds with system reliability. I also expect that independent power producers will not be as interested as a traditional vertically integrated utility would be in trying to prevent the grid from collapsing. I expect that at least some of them would just as soon shut down as quickly as possible instead of riding the disturbance out. We have to ensure they do not do this or it may have catastrophic consequences.

2.17 Short time delays being proposed for generation protection at frequencies close to 60 Hz is a huge risk to the grid, (i.e. at 59.3 Hz, 60.7 Hz)

We need to allow much more operating time at the frequencies closer to 60 Hz than what the NERC standards drafting teams are proposing in PRC-006 and PRC-024. The proposed time delay limit says we can only operate at or below 59.3 Hz or at or above 60.7 Hz for 30 seconds. This is completely unrealistic and a huge threat to system reliability because these standards are essentially giving generation permission to set protection relays accordingly. Remember that once generation starts to trip on underfrequency it can quickly cascade into a blackout. This entire subject of what is appropriate for generation off-nominal frequency protection is something for the experts in study groups to work out, and should not be addressed in either of these standards.

At frequencies close to 60 Hz the appropriate generation protection time delays need to be on the order of 30 minutes or longer instead of 30 seconds as proposed by PRC-006 and PRC-024.

The analysis we did in MRO indicates there is a chance that we will take longer than 30 seconds to get above 59.3 Hz even if our UFLS program works as planned. Remember we did this “bandwidth” type of analysis so we looked at more conditions than most have. We looked for those narrow windows of vulnerability where things “stick” or respond in a sluggish fashion. We can show that any UFLS program will have some combinations of overload and modeling assumptions where frequency recovery is

slow and sluggish. If you don't look for this problem, you are not going to find it, so we conclude the other regions would have as much trouble meeting this as the new MRO UFLS program. Perhaps an intuitive example will help. Basically over the range of coverage provided by load shedding, there will be certain combinations of factors which lead to frequency settling out just above where the next block picks up, and then we have to rely of governor action (or additional small blocks of load shed on delay) to pull the frequency back up. The rate of frequency recovery is also going to be a function of inertia, and if we have lots of units on which are partly loaded, the effective "system based" inertia will be high and rates of change of frequency will be lower. In comparison, if frequency would have dropped a little lower we would have quickly shed load and driven frequency up above 60 Hz, potentially reaching our maximum frequency. Another example to consider is what happens if the system overload is just a little larger than the size of the UFLS program? All load is shed and we are still below 60 Hz, but frequency might be close enough to 60 Hz for operators to respond if they are given sufficient time to respond.

2.18 Generation protection settings also have to anticipate what happens if UFLS fails

My biggest concern with use of short time delays at frequencies above 59 Hz is based on a completely different issue. Murphy's Law is alive and well when it comes to power systems. All of us have to consider what might go wrong during a system breakup. Breakups can be chaotic and different each time they happen, and consequently load shedding performance can vary. There is a chance the "perfect plan on paper" may fail to work as desired in the face of some unanticipated event. At some point operators may have to intervene, and they need assurance that generation will not be tripping as they manually try and drop load. The fact that frequency can stall us out below 59.5 Hz is reason enough to insist that we use generation protection time delays according to actual equipment capabilities. In general, generation off-nominal frequency protection time delays need to be longer than the expected frequency recovery times shown in simulations to give us some margin, and as we get closer to 60 Hz, we want to take advantage of the long delay times allowed by actual equipment capabilities. This is needed as part of the "hedging our bets" process. This helps compensate for the uncertainty we cannot factor into the program design like relay failure, operator error, random events, loads changing in real time (affecting block size as % of system load), effects of voltage transients that effectively increase load, and so forth.

A real life scenario many of us have seen before is where UFLS programs cycle between underfrequency to overfrequency and back into underfrequency. On the second drop into underfrequency, we no longer have all or any of our automatic load shedding left. With luck, the frequency will stall out close enough to 60 Hz to allow manual operator initiated actions. Planners try to prevent this in the design, but in real life this cannot always be prevented. For instance, load shedding itself can overstress lines and cause further breakup of an island into smaller islands, one with a surplus of generation and one with too much load. The island with too much generation is going to suddenly have severe overfrequency problems. Emergency overspeed controls which are in place to deal with full load rejection will kick in somewhere above 61.2 Hz (as previously described). At steam plants these load rejection controls will slam all valves shut. Power plants can't stay in this condition for very long before something gives. Let's say this leads to unpredictable random tripping of thermal generation, and frequency drops back below 60 Hz. As frequency drops the remaining steam turbine valves open back up, so the initial loss of generation my save the rest of the generation and frequency may actually settle out below 60 Hz, but with frequency still high enough that actual equipment capabilities would allow operators plenty of time to respond. We need to take advantage of this capability, and set generation tripping times accordingly.

Another example would be having an overload which is slightly higher than the size of the load shedding program. All load is shed, but frequency remains below 59.5 Hz. We then rely on manual operator actions to pull us back the rest of the way.

2.19 A very troubling trend

One of the most troubling things we uncovered in the MRO UFLS effort is that some manufacturers are now designing equipment which does not have the off-nominal frequency capability it once had. It seems this has occurred with CT's and is probably also happening with wind generation. I mention this trend as it is important that we don't build in weak links like this as the system expands or else we are going to seriously affect reliability. We need units which can briefly operate down to at least 57 Hz to improve chances of surviving islanding events. Future trends in general are all at odds with being able to create a good underfrequency safety net. If NERC prescribes limits which never allow us to operate below 58 Hz, or to limit operation at 59.3 Hz to only 30 seconds, equipment will start being built accordingly.

Combustion turbines cannot hold constant power as frequency drops unless they were only partly loaded to begin with. There are thermal issues involved, which is why fully loaded units only have a momentary governor response to underfrequency. The governor is quickly overridden by the thermal controls. The percentage of power which drops off due to a frequency decline is going to be about the same percentage as the percent change in frequency, or higher. A lot of new CT's have been added over the last 10 years or so, and we are likely to see more of these in the future.

High concentrations of wind generation are really going to cause problems unless more sophisticated designs are used. The problem is that older units are inherently unstable and will just trip off right away. Newer units can probably operate down to 57 Hz, but all inertial effects are masked from the system, so system inertia is going to drop and UFLS relay coordination is going to become very difficult because that low inertia means high rates of change of frequency and this can affect load shedding

programs in several ways. In the MRO UFLS program, we anticipated this problem and examined lower “system based” inertia than what we have today. We saw coordination problems, but this information was still used to help us define a robust UFLS program. It was obvious that coordination would be next to impossible if inertia got lower than what we looked at. Lower system based inertia means lower minimum frequencies and higher frequency overshoot. (This is a consequence of relay detection times and breaker operating times being too slow to stay on top of the fast drop in frequency, so we end up with relay coordination problems and shed too much, too late.) I am not aware of wind units having any type of governor although I was told by an individual in GE’s Power Systems group that designs will be changing over the next 10 years. For instance, GE is adding a governor to their wind generation. I am not sure how that works. Most likely it would work well on overfrequency, but I am not so sure about underfrequency. Likewise they might be able to use software that controls the power electronics associated with variable slip induction generator to unmask the inertial effects (or mimic such effects) to help the grid a bit. However, actual inertia of wind generation is still going to be low. I also heard that a new trend is going to be use of permanent magnet synchronous generators for wind generation. Synchronous generation is probably going to be an improvement over induction generation, but I have no idea if this will actually be a benefit to the system or not. Whatever the wind industry comes up with, it is unlikely to be as robust and useful as traditional steam and hydro generation, and it will just make the task of providing a safety net all the more complex, or perhaps nearly impossible, once huge amounts of wind generation are added to the grid.

3.0 Observations concerning historical reliability criteria, and a proposal to adopt a different type of “measure” to assess UFLS reliability

3.1 Reasonable Expectations

It appears that engineers recognize that we cannot apply performance measures to real life load shedding events since it would be an inconsistent application of how we apply operating type criteria in general to such low probability multiple contingencies. In addition, the parties who are trying to fix the problem do not need to be blamed for the problem itself should they be unable to “fix it”. That is sort of pointless. I believe that engineers also seem to recognize the only perfect program that exists is the one on paper. In real life it has to deal with things we probably have never anticipated and if disturbances are too severe, load shedding may not prevent collapse. Load shedding is just a tool and it has limits. That is just an engineering reality. It should also be obvious that a lot of coordination is involved.

3.2 Coordination is the key to ensuring reliability objectives are met

Good coordination is going to be what ensures reliability. However we sure seem to be doing things which discourages coordination at large. This new deregulated world has defined transmission as separate from generation when in reality all these parts together form a giant complex machine called the “system”. For compliance, we created the concept of “Legal Entities” who can be sanctioned, and entities such as NERC regionals that are apparently something else. We invented terms such as planning coordinator. This all gets confusing, especially to me, as I have had little experience with structural changes going on. What I see is that much of the carefully built up infrastructure that we had to promote reliability is being altered to the extent it is hard to recognize just where we are at today. As we keep creating distinctions which do not follow engineering realities, it will just make all of our coordination tasks much harder to achieve. It is hard to see how this helps reliability. For instance, I was told the NERC regions cannot be in charge of design and analysis of UFLS programs (in conjunction with members of course) because they are not a “Legal Entity”. However this is how reliability matters were always coordinated and this is still the logical way to achieve coordination between all of the parties who need to get involved. All of us in the industry have to work together and pull in the same direction to develop an appropriate safety net. The NERC regions have the organizational structure to pull everyone together to do this type of coordination through taskforces that represent the industry at large. It is necessary to get a broad base of different people involved in the UFLS study process. It ensures you have lots of eyes on the product, lots of different viewpoints to consider, and it also helps in selling and explaining the final program to everyone in the end.

3.3 We have to consider the system in total

When it comes to analysis, the power grid is all one giant complex machine all the way down to the customer load. You have to consider all the parts to figure out the dynamic response of the whole. We have to consider everything which affects the frequency decay dynamics. There is no distinction that can be made on the basis of voltage class of the components of the system. This is why I am a little uncomfortable with excluding some generation from having to coordinate with load shedding programs as done in PRC-024 and PRC-006 just because such generation is connected to a lower voltage. If such generation, in total, is significant to the study work and final UFLS program, then it needs to be included. Let the study group decide what is significant or insignificant.

3.4 The evolution of PRC-006

I understand that PRC-006 has now evolved into something closer to a “continent wide” planning type of standard to guide us in designing UFLS programs. I have tried to explain why the tradeoffs associated with load shedding programs are best evaluated by groups of technical experts which are closest to the problem and why this standards process should not be micromanaging the analytical process or be setting design type of performance criteria. Likewise, it is a poor idea to have a standard such as the proposed PRC-024 that tries to establish generator protection settings up front. I see these approaches as

actually being a threat to reliability by providing the wrong incentives (I also have technical reasons why I do not agree what is being proposed). NERC should allow the technical groups to work out these types of details. Such groups can give this subject the thought and focus that it deserves, and this careful deliberate thought process is what will ultimately ensure we are meeting reliability objectives.

3.5 A recap of my concerns

I believe that I have explained why I am uncomfortable with the idea of using specific frequency and voltage characteristics as a design "measure" in the UFLS standard. I will recap the issues. The various performance objectives of limiting underfrequency, limiting overfrequency, and of providing the largest safety net possible are mutually exclusive. The easiest way to satisfy all three (perhaps the only way) is to put in a smaller program and then the program will work well over this smaller range of overloads but will be inadequate if larger overloads occur. I believe we need to allow programs which are larger than the minimum, when appropriate, and those programs will have poorer performance according to these "measures" but I will argue that only the program which is "large enough to get the job done" will give us the reliability we are looking for. I also recognize there are limits to what UFLS can accomplish, which is why I do not want to mandate that UFLS programs have to shed more than the stated minimum, but I want to encourage folks to do this if it makes sense. Neither the frequency nor the voltage "measures" really tell us if we have the right safety net in place and both measures are subjective (i.e. what performance for what set of assumptions). Concerning voltage, I recognize that volt/Hz issues exist, but I do not feel this needs to be addressed in the standard. The real issue is how to minimize overvoltage problems as we shed load.

To some extent I believe this discussion also helps explain why it can make sense to have different UFLS programs for different portions of the system. That is because different areas have different needs, and possibly unique regional aspects to consider. The final UFLS program definition is just an outcome of working though the problem and iterating towards a best compromise for UFLS program design.

There is no one single "best" program. We have lots of options and each represents different tradeoffs. In reviewing technical literature, we find there are also lots of different opinions expressed by different authors, and I imagine this influenced how programs were created in the first place. I believe the existing load shedding programs in North America are probably getting the job done as long as coordination with generation protection has been achieved. Some programs may be a little more refined than others, but load shedding is inherently a crude and drastic action. A periodic review process will go a long way to ensuring we keep programs up to date. We do not want this review process to be too much of a burden, but we want some process in place so that we can do detailed analysis if needed. My experience has been that a full blown UFLS study process will take 2 to 3 years to complete, perhaps 1 to 1.5 years if folks are fully trained, spend all their time on this one subject, have the study scope worked out ahead of time, and have all the tools developed that are needed. That is what it took groups I have been involved with to collect the information, to build the models, to run meetings, to do the analytical work, and so forth. I would not want to have to do that over and over again on a 5 year schedule. A much more simplified review would be appropriate for the 5 year review. A full study mode type of ground up review is only needed once in a long while or in response to some major break up or in response to drastic changes to the topography of the grid.

I feel that UFLS "measures" used for compliance purposes should stay away from frequency and voltage. We need a different type of measure. UFLS is really sort of something different and unique, and I think that justifies treating it differently than other Standards to the extent that it makes sense to do so. All the other criteria try to keep us from ever getting to this point. UFLS is what we do when we are past the point where most criteria apply. It is a drastic, one shot, last ditch effort and we can't make it into something other than what it is. Some accelerated loss of life to equipment will be involved. Loss of equipment life and financial costs are also associated with a system that goes black. We need to consider all of these tradeoffs, especially when people get too conservative on generation protection to the point where if affects UFLS performance objectives. We need flexibility to accept the right tradeoffs. The UFLS standard can avoid the subject of voltage and frequency performance altogether since we know this will be addressed in the study process in an appropriate level of detail.

3.6 A suggestion to adopt a completely different type of "measure"

I have consistently stressed how UFLS analysis is an iterative process. I hope everyone can understand why I feel this standards drafting process also has to be iterative, and why we may need to change course as we move along the learning curve.

I believe the standards drafting teams need to back up and try a different approach which emphasizes "measures" which consider a completely different aspect of UFLS related effects on reliability. The question is, what are the right measures? The first thought that comes to mind is that load shedding enhances reliability by creating a safety net. Perhaps we should be only be checking to see if the safety net exists, to see if studies say the safety net is an appropriate safety net, and so forth. Would it be possible to use these aspects of the issue as our "measures"?

I think it makes perfect sense to "measure" if we are fulfilling the basic aspects of load shedding obligations. The "measure" would be "have you done activities x, y, z?". We would then skip this entire discussion of what type of performance, on paper, is

appropriate. Instead we would focus on the big picture, which is to make sure we have a reasonably effective safety net in place. The “measures” could become simple pass/fail checks to see if we have covered the basics of implementing an appropriate UFLS program. I suggest that we keep it really simple. It will be easy to check on things like: 1) has an appropriate program been designed which satisfies a checklist of items that have to be considered such as coordination with generation protection, 2) has the program been implemented, 3) has the program been periodically reviewed, 4) have any changes that came about from the review processes been implemented in a timely fashion, and so forth. I know I am in the position of having to sell this approach, as this is not what FERC and NERC set out to do. However, when you look at all the complexity involved, and what the bottom line is, this approach makes sense. I am sure it would be acceptable to the industry and that it would satisfy reliability objectives so long as we get the appropriate study groups in place. That really means getting the right people involved, who have the needed skills to work through things. I think a NERC region has the organizational structure to pull this type of coordination off. We are all familiar with that structure. Inventing some new type of group structure just adds another layer of confusion to deal with.

The standards should stick to the broad-brush type of stuff. More to the point, this standard should be written to ensure the following:

* That Automatic Underfrequency Load Shedding (UFLS) programs are properly developed, documented, and coordinated. This includes coordinating generation off-nominal frequency protection settings with the expected frequency recovery characteristic of the load shedding program.

* That groups/regions have studied UFLS and have designed an UFLS program that fits the unique characteristics of the region (including any subregions) and that UFLS programs address any specific issues that are relevant to UFLS.

* That groups/regions have documentation that specifies the details of the desired UFLS program so it can be implemented.

* That groups/regions do periodic reviews including reports on actual UFLS performance following major disturbances.

* That individual utilities have implemented load shedding in a fashion which is a reasonable fit to the stated regional load shedding program and that documentation is available (the term “reasonable fit” is used in consideration that no single utility can ever get a perfect match to a something like 5 blocks of 6%).

* That each group/region sheds at least a minimum amount of load.
That some form of coordination or dialog exists between groups/regions which study load shedding in adjacent areas.

* To ensure that modeling data is collected and compiled for stability cases

We recognize that PRC-006 addresses some of these points adequately, but as previously discussed, we have serious concerns with how some of this is being handled.

Let the groups/regions define:

* how much load to shed in total (it is OK to set a minimum level in the NERC standard, so long as we are clear that this implies a higher level might be more appropriate)

* size of load shedding blocks

* frequency setpoints

* targets for min/max frequency deviations and allowable times above and below 60 hz (these are design targets only, and may have to be reconsidered and revised after looking at study results…this is an iterative process that has to be carefully thought out as study work proceeds)

* generation off-nominal frequency tripping minimum time versus frequency protection settings to ensure coordination with load shedding

* analytical methods

* any other unique requirements or aspects of regional programs

3.7 The existing NERC UFLS related guidelines and criteria are excellent

As far as UFLS design goes, the broad guidelines in the existing NERC UFLS related standards are excellent, and following that lead will allow us to reach the correct final conclusions. Somehow we have to retain all of these guidelines.

4.0 Can the measures in PRC-006 be tweaked, and is that even a fix?

I believe the direction taken in PRC-006 and PRC-024 is seriously flawed making a discussion of how to tweak and fix things sort of meaningless. That is why I am proposing we adopt “measures” that are based upon the “activities” required to get a safety net in place instead of a measure of “technical details”. However, if we are unable to change directions, then the proposed performance “measures” have to be softened to allow exceptions as based on needs identified in analytical work and to base criteria on actual equipment capabilities. We need a lot of freedom so that groups can make the needed compromises and adopt the right performance criteria.

I really don’t think that PRC-006 should be a planning type of standard that tries to micromanage the design process. My opinion is this approach will not ensure reliability objectives are met. We only need to point out the various issues which planning engineers have to consider (this is clearly spelled out in old NERC UFLS standards) and they can take it from there and work through the study process. Planning engineers will understand what needs to be done better than anyone else. Just turn them loose and they will get the job done, and then we will have the UFLS program specifications complete with criteria on how to coordinate with generation protection.

The existing NERC UFLS related standards are still highly relevant materials which should be used as guidelines on how to develop load shedding programs.

While it is reasonable to start with tentative performance targets as far as design work goes, I consider this as something best left to a study group of the technical experts. Study work has to be performed to find out what is possible before you reach a final decision about what is the best compromise for an UFLS program. In the end, the final program will have to consider if a given area has any unique characteristics that have to be considered, and study work will involve tradeoffs and compromises concerning minimum frequency, maximum frequency, time spent below 60 Hz, and so forth.

4.1 List of specifics related to PRC-006.

R1- a group of planning coordinators is not going to be the equivalent of the type of broad based participation we have historically achieved through the NERC Regionals via the existing committee structure. The group concept is a step in the right direction, but the concerns that we can only apply mandatory standards to “legal entities” appears to be leading to artificial constraints that are making it more difficult to achieve the needed coordination and this just makes it more difficult to create the safety net that we want.

R2-stresses consistent application across the region, and I would argue that only the final analysis of the system will tell you if this makes sense. There may be subregions which have different needs. In MRO, the Canadian systems have different needs than the US portion of MRO.

R3- this says we need criteria on how to select islands. It strikes me as odd that we need “criteria” on how to reach a conclusion. Shouldn’t this just say that analysis shall consider possible system break up patterns that may form islands? For the US portion of MRO, we did not try to say what the most likely island would be. Instead we identified where the break points were, and used this, along with the MRO geographic boundary, to break the system into pieces. We felt these pieces alone, or aggregated together, represented our possible islands. We evaluated the needs of each of the pieces, and evaluated how to model each piece. We concluded that one set of simulations covering a range of inertia, damping assumptions, and overloads would inherently cover all of these different islanding patterns. So we performed our analysis in a fashion that allowed us to avoid having to make a very specific determination of what the island would be, and instead found a way to make something work in a more global sense.

R4-I agree that coordination with neighboring regions is required, but I do not know how to resolve differences of opinion between regions. Perhaps this is nothing to worry about since it is likely to take care of itself. Are we trying to reach a consensus between regions, or just trying to share information and to create a forum for discussion? Obviously where breakups cause islands that straddle different NERC regions, we need to jointly evaluate that island. Even if this coordination is only to share information, it still allows everyone to learn from each other and is going to be quite valuable.

R5-is about identifying islands. I think it is the exact wording of this section that bothers me although I agree with the intent. I prefer to focus on break points that may lead to islands. The difference is subtle, but for the US portion of MRO we did not identify “an island”, in the traditional sense, that was the basis for our design. We identified how the grid may break up. We used these break points to break the system down into pockets of load and generation, and then we examined each pocket. These

pieces, alone or aggregated together, are our possible islands. We did not try to say which was most likely to form. Some of this represents high unlikely conditions. Some of our parts were not even expected to be islands, and were just the left over parts of the foot print after the obvious break points were identified. The southern and eastern edge of MRO is tightly interconnected and less likely to island, but we still were able to reach a conclusion as to what load shedding level was appropriate for even these areas. We examined load shedding requirements and modeling characteristics of each part. In the end we decided that a 30% load shedding requirement was adequate for each "piece" except for the systems in Saskatchewan and Manitoba. The MRO approach was to allow those regions to have their own programs, so they could satisfy their needs, and we just concentrated on the US portion of MRO. In the US portion of MRO, we found an UFLS program that should work for any of these island patterns as each of the geographic regions we looked at had similar characteristics and load shedding needs. We could model a range of conditions using the equivalent inertia modeling approach and we would inherently capture everything at once. Although our analysis was rigorous, we avoided having to decide on what our island has to be for design purposes, and instead came up with something that is likely to work for about any islanding pattern. With this said I can propose a wording change, I would rather say something like:"…shall identify islanding patterns that can be used as a basis for designing an UFLS program. This shall consider:"

R6-addresses the "technical parameters" that I have so much trouble with. I have problems with all of this, as previously discussed at length. I do not like R6.1, R6.2, R6.3 at all, but as part of the study process we would normally come up with parameters of this type after we work through all of the tradeoffs. However I expect we would decide on different technical parameters in the end than is being proposed in PRC-006 and PRC-024. Requirement R6.4, the volts/Hz requirement, does not seem appropriate, and may not have to be addressed at all in an UFLS program. The need to address volts per Hz would depend on how low of a minimum frequency we are expecting. This does not appear to be an issue for programs where the minimum frequency is above 57.2 Hz or so. This might be relevant to isolated hydro systems with large load shedding requirements because hydro systems can accept much lower minimum frequencies than thermal generation (below 57 Hz) and load shedding programs may want to exploit that characteristic. However this would be something that study groups would apply as needed, and does not need to be in a standard.

R7-is about the need to do periodic assessments. I agree we need a periodic assessment of some sort. Full blown studies on the other hand are seldom required unless some inherent flaw in an existing program is identified and we need to start with a fresh look at everything. I do not agree with meeting the performance characteristics in R6. We should meet performance characteristics which are defined as a result of the load shedding study process, and not just something that is tossed out up front.

I think there are other ways to assess the risk of having units trip off early than just running simulations. This almost implies we have to use full stability cases as our only analytical method. Let engineers figure out how to study the problems using whatever tools, methods, and calculations they feel are appropriate.

If we require some assessment of load shedding "need", then generation which drops off early can be evaluated in terms of how it affects the "needs" assessment, or we can demonstrate how loss of such generation affects programs in a general sense. Personally I feel we should not allow any generation to trip any sooner than prescribed by the final UFLS programs requirement for generation protection settings and delays. On second thought, there will be a few exceptions: units which are unstable like the older wind units, non-utility generation tripped along with load on a feeder as part of UFLS, and perhaps other exceptions where inadvertent tripping cannot be avoided. However, as a general principle, we should not allow any generation to trip prematurely via dedicated under frequency relays unless some offsetting action like tripping additional load can be done. We should not allow generation tripping on overfrequency using dedicated relays (other than tripping actions related to load rejection protection that we do not want to be messing with), unless such overfrequency tripping of generation is a planned activity that is a feature of the UFLS program used to rebalance load and generation.

R-8 shouldn't this database/modeling type of information be compiled as part of the regional model building process? NERC regions do this type of thing today, why is this group of Planning Coordinators getting involved in this. We use the NERC regions to do our coordinating activities, so why depart from what works? I need to understand the reasoning behind this before I can comment further.

R-9 appears to say that everyone shall trip load in accordance with the UFLS program. I agree with the intent.

5.0 Appendix

I wrote a lengthy document and sent it to NERC when the first draft of this standard was out for comment. As I just emailed that document in directly and did not submit that document through the on-line data forms where comments are provided, my critique did not show up along with all of the other comments. So, I am submitting some of this again as an appendix. Below are the portions of my original document which address the physics of the problem. I imagine some of this has already been discussed above. However, this is still a good review.

5.1 UFLS in Context

Before we can really address the Under Frequency Load Shedding Regional Reliability Standard Characteristics document in specific detail, we need to provide a context.

Reasonable expectations:

* Under frequency load shedding (UFLS) is a one shot, last ditch attempt to save the grid from total collapse for some event that typically far exceeds anything that planning or operating criteria addresses.

* Load shedding is inherently a crude and drastic action.

* Load shedding has its limits, it can't protect against everything.

* There is no perfect UFLS plan, just lots of different options with lots of different tradeoffs.

* In any discussion of UFLS, we need to keep in mind that load shedding might not work as desired in real life, and we can only make it "perfect" on paper, for some tightly defined scenario subject to a lot of assumptions.

* Just about any UFLS program will work great for some overload level, but at a different overload levels it might shed too much and cause a frequency overshoot or shed too little and then frequency might stall out. We can try to minimize such problems, but not totally eliminate them.

* Doing "something" to try to quickly correct a major load/generation imbalance is better than doing nothing, and history has shown that load shedding generally works well, but it is not always trouble free. Don't penalize honest efforts to provide a safety net.

The best we can do is to eliminate any obvious flaws in the UFLS program design and try to anticipate complications.

5.2 Trade-offs, Compromises, and Uncertainty

When it comes to designing a program, engineers find there is considerable uncertainty associated with most every aspect of the problem. Consider:

* We do not know what may lead to break up, or necessarily what islands may form or what the final imbalance may be.

* There is no perfect way to determine how islands will form, especially if the region is tightly interconnected. Study tools such as stability cases may help identify possible islands, but experience and engineering judgment is perhaps more important.

* Factors that affect load shedding performance are not necessarily under the control of the utilities who put in load shedding.

* At best, we can bracket a range of unknowns and make educated guesses, and then try to find a program that works as intended, the most often, over the widest range of conditions.

* This type of work involves lots of trade offs and compromises.

Compromise also applies to simulation methods. No simulation approach is going to be perfectly suited for this type of analysis and each of the standard ways of assessing UFLS has strengths and weaknesses.

* Full stability cases are very detailed and good for a very specific spot check, but poor for generalizing. They do not necessarily provide a better way of assessing system performance than a more empirical approach.

* Relay application guides typically suggest using the equivalent inertia approach to dynamic modeling where everything is equivalized down into the simplest form that captures the frequency decay dynamics. This simple approach allows rapid prototyping, but it ignores the voltage transients and governor action.

To better understand the complications of UFLS design, we need to give a brief statement of the problem:

* When we have a mismatch of load and generation, the frequency will decay or increase until we reach a new equilibrium between generation torques and load torques.

* If generator power stays constant, then generation torque will increase as frequency drops (power = torque x speed).

* Load torques decrease as frequency drops according to the load damping constant.

* At some new frequency, we once again reach equilibrium where load and generation torques are equal and this becomes the new synchronous frequency.

* Without load shedding we could see frequency decay low enough that generation protection will have to instantly trip generation to prevent excessive loss of life. At that point, the system collapses.

Load shedding objective and tradeoffs:

* We use UFLS to quickly drive frequency back towards 60 Hz so that we do not risk losing additional generation on underfrequency.

* Loadshedding must not cause overfrequency problems that lead to uncontrolled tripping of generation that will precipitate another underfrequency event.

* To improve minimum frequency, we can start shedding sooner (higher frequency setpoints), decrease frequency spacing between relay settings, and shed load in fewer blocks of larger size…all of this increases frequency overshoot problems.

* We can also improve minimum frequency by deciding to cover a smaller imbalance to begin with.

* To decrease frequency overshoot, we can shed load in smaller blocks, increase frequency spacing between relay settings, and use more load shedding blocks in total…all of this decreases the minimum transient frequency for the largest overloads we cover.

* Overfrequency based tripping of generation or restoration of load can also minimize frequency overshoot, at the risk of causing the frequency to cycle back into another underfrequency event.

* Underfrequency recovery times can be improved by shedding some additional blocks of load on delay, at the expense of increasing the risk of frequency overshoot.

The rates of change of frequency and load damping characteristics affect relay coordination:

* Large overloads give high rates of change of frequency

* Unit inertia represents energy stored in the rotating mass. Inertia (for a given overload level) affects the rate of decay of frequency: high inertia = slower frequency rate of change, low inertia = fast frequency rate of change.

* Load damping affects the final frequency where equilibrium is reached. Low damping means larger frequency deviations for a given imbalance.

* Generally it is difficult to design a program for low inertia, low damping, high overload conditions. This condition gives the lowest transient frequency, and the fast frequency decline affects relay coordination that can cause overshedding.

* Relay coordination is much easier if inertia is high, but recovery back towards 60 Hz will be slower when inertia is high.

Let’s consider some of the hard to quantify factors that affect performance:

* load damping (utilities have no control over the dynamic characteristic of loads, and we are not sure how much damping we have or how it varies in time or by season)

* the type of generation on the system

* the system inertia on system base (energy stored in rotating mass relative to remaining generation in island)

* if asynchronous islands are still being fed by DC lines (this is power with no inertia associated with it, which drives system based inertia down), or if frequency deviations cause DC lines to trip

* the magnitude of the imbalance between load and generation

* the net governor effect (not much if units are base loaded, running in boiler follow mode, or overridden by power-load controllers)

* overvoltages (and how can we moderate voltage deviations)…as load is shed the voltage will swing around, and overvoltages can increase load, offsetting the benefits of load shedding which in turn affects the rate of frequency recovery

* random factors, such as unit trips, industrial load trips, additional line outages (including planned separation schemes), and so forth

* Wind generation…the older vintage of wind generation will drop off-line as frequency declines…how much will be on-line?

* Combustion turbines…they are thermally restricted. Assuming a combustion turbine is operating close to its temperature limit to begin with (i.e. the typical condition when loaded high), the net result is that turbine power drops as frequency starts to decline, aggravating the imbalance.

* The actual sequence of events that leads to islanding can have considerable influence on overall performance, yet typically the best we can do in simulations is to form and island all at once by opening all the tie lines at the same moment. This is because we do not get major system breakups from “credible events” that we can easily model. Usually load shedding occurs following a complicated sequence of things going wrong that no one could have ever predicted ahead of time.

* Load shedding itself may overload transmission lines, and lead to further system breakup and islanding.

* Overshedding can lead to unintended random loss of additional generation in response to overspeed (due to various internal problems at the facility), and cause another cycle into underfrequency from which we might not recover.

Now consider future trends:

* Industry trends show that load damping is decreasing, and load damping is not precisely known to begin with. Damping also varies in real time.

* The trend has been that inertias of new units are lower than in the past.

* Some of the newer wind generation provides no inertial effects as rotating mass is decoupled from the electrical grid by the controls that allow variable slip operation of the induction generator or because they are coupled to the AC system through an inverter.

* Wind generation is intermittent, difficult to factor into UFLS programs, and with all of the different makes and models out there, it is difficult to generalize how these units will actually respond and how many will ride through a frequency swing.

Different areas have different load shedding needs, and areas that need to shed a lot of load have to make more compromises as far as transient frequency and voltage performance go:

* UFLS programs that shed more load will also experience lower minimum frequencies, higher maximum frequencies, and be more prone to relay coordination problems (which increases the chance of overshedding). On the positive side, these programs provide the largest safety net.

* Programs which shed the minimum amount of load can use smaller load blocks or fewer load shedding stages which improves frequency response and improves relay coordination over the smaller range of overloads covered. Obviously if overloads exceed the capacity of the program, the system will collapse.

In summary, everyone needs to apply common sense and good judgment when dealing with UFLS issues, and compromises have to be carefully considered at every step of the decision process involved with design and implementation.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on 3rd Draft of Underfrequency Load Shedding Program Requirements — Project 2007-01

The Underfrequency Load Shedding Standard Drafting Team thanks all commenters who submitted comments on the proposed 3rd draft of the PRC-006-1— Automatic Underfrequency Load Shedding Standard, EOP-003-1 — Load Shedding Plans, and the associated Implementation Plan. The standards and implementation plan were posted for a 35-day public comment period from June 11, 2010 through July 16, 2010. Stakeholders were asked to provide feedback through a special electronic comment form. There were 41 sets of comments, including comments from more than 100 different people from over 55 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Summary of Changes

During the third posting of PRC-006-1 and EOP-003-2 the standard drafting team made several conforming changes as a result of the industry comments received.

- The fourth version of the proposed standard addresses the coordination issue many commenters expressed. Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 require concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. Requirement R14 was added to provide peer pressure in responding to concerns about UFLS programs.
- Commenters expressed confusion over having Transmission Owners as possible UFLS Entities but separated out as Transmission Owners in Requirement R10 and suggested merging Requirements R9 and R10. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements.
- Commenters expressed that the wording in Requirement R10 “switching of elements” is confusing. The team modified Requirement R10 to clarify that it means: “switching of capacitor banks, Transmission Lines, and reactors” to control over voltage as a result of under frequency load shedding.
- Commenters suggested that R13 was unclear, and the team revised the requirement by deleting the phrase, “. . . of UFLS actuated loss of load occurs. . . ”
- Many commenters indicated that Generator Owners should be included in the applicability of the standard. Some suggested including a data requirement in PRC-006-1 that requires the Generator Owners to submit the necessary data to accomplish Requirement R4; however, the team felt that because such a data requirement already exists in PRC-024 and because the team has clarified in the effective date of the standard that the Parts of the requirement related to generators will not be effective until PRC-024 is approved and effective, that adding such a data requirement to PRC-006 would be redundant and possibly cause double jeopardy concerns.
- The phrase, “Planning Coordinator footprint” was changed to “Planning Coordinator area” throughout the standard for improved clarity.

- The team also made modifications to clarify the performance characteristics in Requirement R3.
- The team modified Requirements R6 and R7 to clarify the limit the scope of the UFLS database.

The standard drafting team received several comments on EOP-003 that expressed concern that the removal of under-frequency load shedding in the standard was not clear enough. The standard drafting team made modifications to the EOP-003 requirements that clarify that the load shedding referred to in the requirements excludes automatic under-frequency load shedding.

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Ben Eng	New York Power Authority	NPCC	4
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Dean Ellis	Dynegy Generation	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick System Operator	NPCC	2
15.	Bruce Metruck	New York Power Authority	NPCC	6

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
16.	Lee Pedowicz	Northeast Power Coordinating Council NPCC 10										
17.	Robert Pellegrini	The United Illuminating Company NPCC 1										
18.	Saurabh Saksena	National Grid NPCC 1										
19.	Michael Schiavone	National Grid NPCC 1, 3										
20.	Peter Yost	Consolidated Edison Co. of New York, Inc. NPCC 3										
21.	Chantel Haswell	FPL Group NPCC 5										
22.	Si Truc Phan	Hydro-Quebec TransEnergie NPCC 1										
2.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Charles Long	Entergy	SERC	1
3.	James Manning	North Carolina Electric Membership Corporation	SERC	3
4.	Jim Kelley	PowerSouth Energy Cooperatiove	SERC	1
5.	Pat Huntley	SERC Reliability Corporation	SERC	10
6.	Bob Jones	Southern Company Services, Inc. - Transmission	SERC	1
7.	David Marler	Tenessee Valley Authority	SERC	1

3.	Group	Bob Jones, Chairman	SERC SC UFLS Standard Drafting Team	X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Foster	Ameren Services Company	SERC	1
2.	Venkat Kolluri	Entergy	SERC	1
3.	Greg Davis	Georgia Transmission Corporation	SERC	1
4.	Ernesto Paon	Municipal Electric Authority of Georgia	SERC	1
5.	Andrew Fusco	North Carolina Municipal Power Agency Number 1	SERC	4
6.	John O'Connor	Progress Energy Carolinas	SERC	1
7.	Pat Huntley	SERC Reliability Corporation	SERC	NA
8.	Jonathan Glidewell	Southern Company Services, Inc.	SERC	1
9.	Tom Cain	Tennessee Valley Authority	SERC	1

4.	Group	Mallory Huggins	NERC Staff									

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Phil Tatro	NERC	NA - Not Applicable	NA
2.	Bob Cummings	NERC	NA - Not Applicable	NA
3.	David Taylor	NERC	NA - Not Applicable	NA
4.	Stephanie Monzon	NERC	NA - Not Applicable	NA
5.	Al McMeekin	NERC	NA - Not Applicable	NA

5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Vasallo	BPA, Tx Customer Service Engineering	WECC	1
2.	Rebecca Berdahl	BPA, Long Term Sales and Purchases	WECC	3

6.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
2.	Jim Detweiler	FE	RFC	1

7.	Group	Joseph DePoorter	MRO's NERC Standards Review Subcommittee (NSRS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Tom Webb	WPSC	MRO	3, 4, 5, 6
4.	Jason Marshall	MISO	MRO	2
5.	Jodi Jenson	WAPA	MRO	1, 6
6.	Ken Goldsmith	ALTW	MRO	4
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
9.	Joseph Knight	GRE	MRO	1, 3, 5, 6
10.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
11.	Scott Nickels	RPU	MRO	4
12.	Terry Harbour	MEC	MRO	6, 1, 3, 5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
13. Carol Gerou		MRO	MRO 10										
8.	Group	Art Buanno	ReliabilityFirst Engineering Staff										X
Additional Member		**Additional Organization**	**Region**	**Segment Selection**									
1. Ray Mason		ReliabilityFirst Corp.	RFC 10										
9.	Group	Richard kafka	Pepco Holdings, Inc. - Affiliates	X		X		X	X				
Additional Member		**Additional Organization**	**Region**	**Segment Selection**									
1. Dave Thorne		Potomac Electric Power Company	RFC 1										
2. Vic Davis		Delmarva Power & Light	RFC 1										
10.	Individual	Shawn Jacobs	SPP System Protection and Control Working Group		X								X
11.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
12.	Individual	Dennis Chastain	Tennessee Valley Authority (TVA)	X		X		X	X				
13.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
14.	Individual	JT Wood	Southern Company Transmission	X		X							
15.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X				
16.	Individual	John Bee	Exelon	X		X		X					
17.	Individual	Ernesto Paon	MEAG Power	X		X		X					
18.	Individual	Kirit Shah	Ameren	X		X		X	X				
19.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
20.	Individual	Robert Ganley	Long Island Power Authority	X									
21.	Individual	John Bussman	AECI	X		X		X	X				
22.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
23.	Individual	James A. Ziebarth	Y-W Electric Association, Inc.				X						
24.	Individual	Jonathan Appelbaum	United Illuminating Company	X									
25.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	Edward Davis	Entergy Services	X		X		X	X				
27.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
28.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
29.	Individual	Jeff Nelson	Springfield Utility Board			X							
30.	Individual	Charles Lawrence	American Transmission Co.	X									
31.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
32.	Individual	Claudiu Cadar	GDS Associates	X									
33.	Individual	Joe Springhetti	Wisconsin Electric Power Company (dba We Energies)			X	X	X					
34.	Individual	John O'Connor	Progress Energy - Carolinas	X		X		X	X				
35.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
36.	Individual	Dan Rochester	IESO		X								
37.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Phillips	MISO		2
2.	Patrick Brown	PJM	RFC	2
3.	Charles Yeung	SPP	SPP	2
4.	Steve Myers	ERCOT	ERCOT	2
5.	Matt Goldberg	ISO-NE	NPCC	2
6.	Mark Thompson	AESO	WECC	2
7.	James Castle	NYISO	NPCC	2

38.	Individual	Bill Middaugh	Tri-State Generation & Transmission Assoc.	X									
39.	Individual	Darcy O'Connell	The California ISO		X								
40.	Individual	Terry Harbour	MidAmerican Energy	X									
41.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X					

1. The SDT drafted Violation Risk Factors, for the requirements. Do you agree with the proposed Violation Risk Factors?

Summary Consideration:

The standard drafting team made conforming modifications to the VRF for Requirement R1 as a result of industry comments received that indicated that the VRF should be higher (changed from Lower to Medium) since the output of this requirement is used in higher VRF requirements.

Several commenters did not agree that the VRFs assigned a medium or higher are appropriate for a planning standard; however, the VRF assignments by definition apply both to operations and planning standards. In the planning timeframe the standard drafting team thinks it has appropriately assigned VRFs.

Organization	Yes or No	Question 1 Comment
Xcel Energy		No comments
The California ISO	No	Cannot support approval until the requirements are closer to being finalized.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Tri-State Generation & Transmission Assoc.	No	Comments: Generally, our primary concern is that the requirements should not apply to individual Planning Coordinators, so it is difficult to agree with any proposed Violation Risk Factors (VRF).The reliability basis for R1 and R2 is not clear and we would recommend eliminating those requirements along with their VFRs.We believe the use of Transmission Owner in R10 is redundant with R9 and "switching of elements" should be merged into R9 and R10 can be eliminated.The five-year assessment in requirement R4 seems like a higher VRF than necessary and Medium would be adequate.
Response: The SDT notes that Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard. The SDT believes the Planning Coordinator is the most appropriate applicable entity because design of a UFLS program should consider the widest possible geographic area. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role, the SDT anticipates that the Transmission Planners' expertise will be utilized. **The SDT thinks that Requirement R1 and Requirement R2 are important parts of establishing a UFLS program and are a necessary part of the proposed standard.** **Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator;**		

Organization	Yes or No	Question 1 Comment
Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements. **This requirement is assigned a High VRF because the reliability objective of this requirement is to perform an assessment of the UFLS program every five years. Violation of this requirement, by failing to validate the UFLS program through dynamic simulations, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.**		
American Transmission Co.	No	The VRFs for R3, R4, R9, and R10 should be reduced from "High" to "Medium" for several reasons. System events that would activate automatic underfrequency load shedding have been very rare and automatic UFLS is a system preservation measure of last resort, not primary system preservation measure. For R4 in particular, the performance of the UFLS program and the associated islands do not change rapidly or dramatically to warrant a "High" VRF for delayed conducting or documentation of a UFLS design assessment.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.		
IESO	No	If the Planning Coordinator does not develop and document criteria, how will other Requirements be satisfied? For this reason, the VRF for R1 should be higher.
Response: The SDT agrees with the commenter and made conforming changes to the VRF for Requirement R1.		
IRC Standards Review Committee	No	No VRF for UFLS should be High. UFLS is only actuated because several other things did not work properly. For a VRF to be High, there must be a direct causal link to bad things happening (i.e. cascading, instability, blackout) as result of the requirement. If UFLS has to be actuated, we have already reached the bad things happening stage and this represents a last ditch effort to save the system.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.		

Organization	Yes or No	Question 1 Comment
Southern California Edison Company	No	SCE does not agree with the proposed reliability standard and, therefore, we cannot agree with the proposed Violation Risk Factors.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Pepco Holdings, Inc. - Affiliates	No	See response to question 7. PHI does not concur with the requirements as written.
Response: Please see our response to your comments on Question 7. The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Long Island Power Authority	No	The VRF for R1 for the development and documentation of UFLS program criteria is stated as a "Low" VRF. Such a requirement to develop overall UFLS program criteria was more than a "Low" or Admininstrative requirement and that the VRF for this requirement should be listed as Medium VRF. The requirement to develop a program criteria in Requirement R1 is as important as those requirements stated in Requirement R2 which was assigned a Medium VRF by the DT.
Response: The SDT agrees with the commenter and made conforming changes to the VRF for Requirement R1.		
Northeast Power Coordinating Council	No	The VRF for R1 for the development and documentation of UFLS program criteria is stated as a Low VRF. Such a requirement to develop overall UFLS program criteria was more than a 'Low' or Administrative requirement, and the VRF for this requirement should be listed as a Medium VRF. The requirement to develop program criteria in Requirement R1 is as important as those requirements stated in Requirement R2 which was assigned a Medium VRF by the DT.
Response: The SDT agrees with the commenter and made conforming changes to the VRF for Requirement R1.		
Northeast Utilities	No	The VRF for Requirement R1 is stated as a Lower. The requirement to develop program criteria in Requirement R1 is as important as those requirements stated in Requirement R2 which is assigned a Medium VRF. Suggest the Requirement R1 VRF be revised to Medium.
Response: The SDT agrees with the commenter and made conforming changes to the VRF for Requirement R1.		
Manitoba Hydro	No	The VRFs for R3, R4, R9, and R10 should be reduced from "High" to "Medium" for several reasons. System events that would activate automatic underfrequency load shedding have been very rare and automatic UFLS

Organization	Yes or No	Question 1 Comment
		is a system preservation measure of last resort, not primary system preservation measure. For R4 in particular, the performance of the UFLS program and the associated islands do not change rapidly or dramatically to warrant a "High" VRF for delayed conducting or documentation of a UFLS design assessment.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.		
MidAmerican Energy	No	The VRFs for R3, R4, R9, and R10 should be reduced from "High" to "Medium" for several reasons. System events that would activate automatic underfrequency load shedding have been very rare and automatic UFLS is a system preservation measure of last resort, not primary system preservation measure. For R4 in particular, the performance of the UFLS program and the associated islands do not change rapidly or dramatically to warrant a "High" VRF for delayed conducting or documentation of a UFLS design assessment
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	The VRFs for R3, R4, R9, and R10 should be reduced from "High" to "Medium" for several reasons. [1] Automatic UFLS programs are system preservation measures of last resort that may help the BES recovery if the primary system preservation measures are insufficient. So, the risk to the system reliability is low because primary measures will normally restore the system even if some UFLS requirements are not completely fulfilled. [2] System events that would activate automatic underfrequency load shedding have been very rare. So, the risk to system reliability is low because events of unacceptable underfrequency rarely occur even if the sum of the UFLS requirements not completely fulfilled. [3] Automatic UFLS programs can only be designed to help preserve the system for a wide range of, but not all, possible system conditions. So, the risk to system reliability is low because UFLS programs may help for many system condtions, even if some of the UFLS requirements are not completely fulfilled. [4] For R4, the performance of the UFLS program and the characteristics of the associated islands change only slightly and gradually over many years. So, the risk to system reliability would not change dramatically if

Organization	Yes or No	Question 1 Comment
		conducting or documenting of a UFLS design assessment was delayed by several years.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.		
Tennessee Valley Authority (TVA)	No	TVA believes the following VRF changes should be considered: R4 - change from High to Medium. Justification: The selection of a 5-year interval for assessments seems subjective in nature. Failure to perform an assessment within a 5-year interval would not directly cause or contribute to bulk electric system instability. R11 - change from Medium to Low. Justification: documenting a post event assessment seems more administrative in nature, relative to R12.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition. **R11- A similar requirement exists in PRC-009-0 Requirement R1 and is assigned a Medium VRF. This requirement is assigned a Medium VRF because it requires assessment of UFLS equipment performance and UFLS program effectiveness during specified events involving UFLS activation that could identify deficiencies in either, and if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of the bulk electric system, or the ability to effectively control or restore the bulk electric system.**		
Western Electricity Coordinating Council	No	We agree that the proposed VRFs are appropriate for the subject of the requirements, but we do not agree with many of the requirements as drafted, so we are opposed for that reason
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
AECI	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 1 Comment
Exelon	Yes	
FirstEnergy	Yes	
Indiana Municipal Power Agency	Yes	
MEAG Power	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC Planning Standards Subcommittee	Yes	
SERC SC UFLS Standard Drafting Team	Yes	
South Carolina Electric and Gas	Yes	
SPP System Protection and Control Working Group	Yes	
Springfield Utility Board	Yes	
United Illuminating Company	Yes	
Wisconsin Electric Power Company (dba We Energies)	Yes	
Y-W Electric Association, Inc.	Yes	
Ameren	Yes	Did the SDT utilize the VRF Tool recently developed by the Process Subcommittee of the NERC SC to develop the VRFs? If not, the VRFs should be revisited using this tool.

Organization	Yes or No	Question 1 Comment
Response: The SDT did not use the VRF Tool. The use of the tool is not authorized at this time.		
Illinois Municipal Electric Agency	Yes	For R8, R9, R10 applicable to UFLS entity/TO.
Response: Thank you for your support.		
Duke Energy	Yes	However we have identified an issue with R5 and R13 requiring that Planning Coordinators "reach concurrence" which brings their VRFs into question. This is discussed further in our comments below.
Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.		
Progress Energy - Carolinas	Yes	We agree with proposed VRFs. However, we would recommend the VRF Tool be used to validate these.
Response: The SDT did not use the VRF Tool. The use of the tool is not authorized at this time.		
Entergy Services	Yes	We recommend that the VRF Tool be used to validate the proposed VRFs.
Response: The SDT did not use the VRF Tool. The use of the tool is not authorized at this time.		
Southern Company Transmission	Yes	We recommend that the VRF Tool be used to validate the proposed VRFs.
Response: The SDT did not use the VRF Tool. The use of the tool is not authorized at this time.		

2. The SDT drafted Measures for the requirements. Do you agree with the proposed Measures?

Summary Consideration:

The standard drafting team received comments to improve the clarity of the Measures and made some conforming changes to the Measures for this purpose, including the following:

- M2 and M3 - Removed the phrase, "including the criteria itself".
- M5 and M13 – Expanded the description of possible types of acceptable evidence.
- M10 – Replaced the phrase, "switching of Facilities" with a specific list of Elements.

Organization	Yes or No	Question 2 Comment
Xcel Energy		No comments
AECI	No	For M1, how can we consider historical events if we have never had a UFLS event on our system? How would a system study tell us how to select an island? This is unclear.
Response: Requirement R1 requires that the Planning Coordinator consider historical events and system studies in selecting island critera but the deliverable for Requirement R1 is a criteria for selecting islands and it doesn't require the entity to have island criteria based on historical events only to consider historical events. The Measure M1 indicates that the entity must have some evidence that it considered historical events.		
The California ISO	No	Cannot support approval until the requirements are closer to being finalized.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Tri-State Generation & Transmission Assoc.	No	Comments: The measures are vague and not performance based leaving much up to interpretation. Measures should contain specific targets or specifications that clarify how an entity will be audited and measured for compliance. These measures merely repeat the requirements and do not provide any useful guidance beyond what is specified in the requirement itself.
Response: The SDT thinks that the Measures identify the evidence or types of evidence needed to demonstrate compliance with the associated requirement. The SDT thinks that the commenter is proposing that the SDT propose the RSAW not the Measures.		
MidAmerican Energy	No	Ensure that measures correctly reflect modified requirement changes. In addition there are concerns with the

Organization	Yes or No	Question 2 Comment
		addition of requirements and measurements to reach concurrence. This potentially subjects an entity to non-compliance based on events beyond that entity's control such as a problematic neighbor that refuses to reach concurrence. This concpept should be removed and replaced with a requirement to distribute the results. Examples include M5 - As noted in the comments below for R5, replace the words "reached concurrence with" with "provided a UFLS design assessment report to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors. M7 - As noted in the comments below for R7, replace "within their Interconnection", with "that have design assessment responsibilities within the islands covered by the UFLS database". Planning Coordinators that are within the same Interconnection, but are not within any islands covered by another Planning Coordinators UFLS database, would not need to receive the UFLS information .M10 - Replace "automatic switching of Facilities" with "automatic switching of Elements" to be consistent with the associated Requirement R10
Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces this with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. **The SDT thinks that database information should be shared beyond that which is being proposed by the commenter. This is the reason why the SDT specified that the PC's share the database with the other PC's within their interconnection. This is a measure to ensure information sharing is happening within the interconnection.** **The SDT made the suggested conforming change to Measure M10.**		
Exelon	No	Exelon does not agree with the concept of allowing neighboring Planning Coordinators to define or modify islanding criteria. There should be a single criteria for the determination of an island which is consistent across the interconnection, unless a specific geographic or regional exception is identified. Even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint.
Response: The SDT is unsure if the commenter is referring to a specific requirement; however, like many other commenters that were concerned with the Planning Coordinators reaching concurrence, the SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators		

Organization	Yes or No	Question 2 Comment
coordinated should an island cross Planning Coordinator areas.		
Progress Energy - Carolinas	No	For M3, it is unclear what is meant by the phrase "including the criteria itself." Since the criteria is specified in R3, we recommend this phrase be deleted from the measure. **Response:The SDT agrees with the commenter and removed the phrase from both M2 and M3.** For M5, this measure should only apply to Planning Coordinators (PCs) who are part of a joint island, but it is written such that it appears to apply to all PCs. We recommend rewording M5 to "Each Planning Coordinator shall have dated evidence...that it reached concurrence with the other affected PCs on design assessment results for any islands in accordance with Requirement R5 and identifies the affected PCs." We also recommend that R5 be reworded to "Each PC shall reach concurrence with all other affected PCs on UFLS design assessment results before design assessment completion for any islands identified by that PC which include a portion of that PC's footprint along with another PCs footprint." **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT also made associated changes to the corresponding measures.**
Ameren	No	In M3, it isn't clear what is meant by "including the criteria itself." The criteria is already specified in Requirement R3, so this phrase does not appear to be needed. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.** M5 should only apply to PCs who would be part of a particular joint island. The present wording seems to suggest that M5 and Requirement R5 would apply to every PC. The wording for M5, and corresponding Requirement R5, should be modified to apply only to the PC's which would be involved with a particular island. **Response: The SDT made conforming changes to Requirement R5 to clarify the coordination between Planning Coordinators.**
Duke Energy	No	M3 - it is unclear what is meant by the phrase "including the criteria itself". Suggest deleting the phrase. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.** Also, requirements R5 and R13 (and hence their Measures and VSLs) are problematic, since they require that Planning Coordinators shall "reach concurrence" with all other affected Planning Coordinators, which may

Organization	Yes or No	Question 2 Comment
		not always be possible. The requirements need to provide for that situation. **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.**
Entergy Services	No	M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that the phrase be deleted. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.** M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. Recommend that the wording in M5 be changed to: "Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified islands in accordance with Requirement R5 and identifies the affected Planning Coordinators." Recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint." **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT made conforming changes to the associated Measures.**
SERC Planning Standards Subcommittee	No	
Response:		
SERC SC UFLS Standard Drafting Team	No	M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that it be deleted. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.** M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. Recommend that the wording in M5 be changed to: "Each Planning

Organization	Yes or No	Question 2 Comment
		Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified islands in accordance with Requirement R5 and identifies the affected Planning Coordinators." Recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint." **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT made conforming changes to the associated Measures.**
Southern Company Transmission	No	M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that it be deleted. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.** M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. Recommend that the wording in M5 be changed to: "Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified islands in accordance with Requirement R5 and identifies the affected Planning Coordinators." Recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint." **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT made conforming changes to the associated Measures.**
American Transmission Co.	No	M5 - As noted in the comments below for R5, replace the words "reached concurrence with" with "provided a UFLS design assessment report to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning

Organization	Yes or No	Question 2 Comment
		Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors. **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT made conforming changes to the associated Measures.** M7 - As noted in the comments below for R7, replace "within their Interconnection", with "that have design assessment responsibilities within the islands covered by the UFLS database". Planning Coordinators that are within the same Interconnection, but are not within any islands covered by another Planning Coordinators UFLS database, would not need to receive the UFLS information. **Response: The SDT thinks that database information should be shared beyond that which is being proposed by the commenter. This is the reason why the SDT specified that the PC's share the database with the other PC's within their interconnection. This is a measure to ensure information sharing is happening within the interconnection.** M10 - Replace "automatic switching of Facilities" with "automatic switching of Elements" to be consistent with the associated Requirement R10. **Response: The SDT clarified Requirement R10 and Measure M10 by explicitly stating the types of Elements.**
Bonneville Power Administration	No	Measures are too vague, lacking specifics, and not performance-based. This would leave too much up to the Auditor's interpretation. Measures are only valuable if they contain specific targets or specifications that clarify how an entity will be deemed to be compliant with the standard as written. Measures which merely repeat the standard with the inclusion of "shall have evidence such as..." are not very useful. Measures should be explicit, detailed, consistent, and provide useful guidance to entities. These measures do not provide any useful guidance beyond what is specified in the requirement itself.
Response: The SDT thinks that the Measures identify the evidence or types of evidence needed to demonstrate compliance with the associated requirement. The SDT thinks that the commenter is proposing that the SDT propose the RSAW not the Measures.		
FirstEnergy	No	Since we do not agree with some of the standard requirements, we therefore do not agree with the measures for some of the requirements as written.

Organization	Yes or No	Question 2 Comment
Response: The SDT has made conforming changes to the proposed standard that addresses many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Manitoba Hydro	No	Suggest that the measures be modified to reflect any changes made to standards Requirements per the comments made to questions Q4 through Q13. **Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.** M10 - Replace “automatic switching of Facilities” with “automatic switching of Elements” to be consistent with the associated Requirement R10. **Response: The SDT clarified Requirement R10 and Measure M10 by explicitly stating the types of Elements.**
MRO’s NERC Standards Review Subcommittee (NSRS)	No	Suggest that the measures be modified to reflect any changes made to standards Requirements per the comments made to questions Q4 through Q13. **Response: The SDT has made conforming changes to the proposed standard that addresses many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.** M10 - Replace “automatic switching of Facilities” with “automatic switching of Elements” to be consistent with the associated Requirement R10. **Response: The SDT clarified Requirement R10 and Measure M10 by explicitly stating the types of Elements.**
IESO	No	The measures that refer to Requirements with subrequirements (e.g. R2, R3, and R4) should be more consistent. **Response: The SDT thinks that the Measures as written accurately refer to the associated Requirement sub-parts.** All of the corresponding Measures (e.g. M2 and M4) should include the final phrase: “including the criteria itself” or none should include this phrase. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.**

Organization	Yes or No	Question 2 Comment
Tennessee Valley Authority (TVA)	No	TVA believes the following changes to the Measures should be considered:M3: It is unclear what action is intended by the phrase “including the criteria itself.” Since the criteria are specified in R3, it is recommended that it be deleted.
Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3		
Southern California Edison Company	No	We do not agree with the proposed reliability standard and, therefore, we cannot agree with the proposed Measures.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Pepco Holdings, Inc. - Affiliates	No	We do not concur with the requirements as written
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
SPP System Protection and Control Working Group	No	What is meant by “criteria” in Requirement R1? Does “criteria” in R1 have to be justified?
Response: The criteria in Requirement R1 is the criteria used to select islands as the basis for the UFLS program design.		
Indiana Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
Long Island Power Authority	Yes	
MEAG Power	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	

Organization	Yes or No	Question 2 Comment
ReliabilityFirst Engineering Staff	Yes	
South Carolina Electric and Gas	Yes	
Springfield Utility Board	Yes	
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
Illinois Municipal Electric Agency	Yes	For M8, M9, and M10 applicable to UFLS entity/TO.
Response: Thank you for your support.		
Northeast Power Coordinating Council	Yes	The Measures are logical and consistent with the corresponding requirements.
Response: Thank you for your support.		
Wisconsin Electric Power Company (dba We Energies)	Yes	We agree with the Measures as far as the draft standard is currently written, however, see our comments for questions 11, 12, and 13 that would require modifications to requirements R9 & R10 and to M9 & M10.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		

3. The SDT drafted Violation Severity Levels for the requirements. Do you agree with the proposed Violation Severity Levels?

Summary Consideration:

Some comments received indicated that the increments in the VSLs were arbitrary. The standard drafting team used the NERC and FERC VSL guidelines to develop the proposed VSLs. However, several commenters suggested making changes to the VSLs such as VSL for Requirement R11 and the team made conforming changes.

The team changed the phrase, “Planning Coordinator footprint” with the phrase, “Planning Coordinator area” throughout the standard.

Organization	Yes or No	Question 3 Comment
Xcel Energy		No comments
The California ISO	No	Cannot support approval until the requirements are closer to being finalized.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Tri-State Generation & Transmission Assoc.	No	Comments: We believe that individual Planning Coordinators are not the appropriate entities to be responsible for determining criteria for areas that may form islands, for identifying the islands, for developing the UFLS program, for periodic assessments, for maintaining databases, or for assessing events. Further, Planning Coordinator footprints are neither defined nor is there any guidance on how they should be established. **Response: The definition of the Planning Coordinator according to the Function Model Version 5 states: The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.** Every VSL that refers to a PC footprint should be clarified. **Response: The SDT replaced “footprint” with “area” to be consistent with the Functional Model.** What is meant by “annually maintain” is neither clear nor defined. **Response: The SDT modified Requirement R7 to clarify the intent of the UFLS database: Each Planning Coordinator shall annually maintain a UFLS database containing *data necessary to model its***

Organization	Yes or No	Question 3 Comment
		UFLS program for use in event analyses and assessments **of the UFLS program.** The VSL for R6 should be re-written.The increment size between VSLs seems arbitrarily small in R9 and R10. Is there a reliability basis for choosing 5%? **Response: The SDT established increments in the VSLs according to the VSL NERC guidelines.**
Bonneville Power Administration	No	Criteria are never actually defined in the requirements. **Response: The criteria in Requirement R1 is the criteria used to select islands as the basis for the UFLS program design.** Planning Coordinator footprints are not established. **Response: The SDT replaced "footprint" with "area" to be consistent with the Functional Model.** **The definition of the Planning Coordinator according to the Function Model Version 5 states: The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.** What does "annually maintain" mean? Does it mean the Database requires annual updates, annual reviews or just to provide a database annually? Frequency excursions precede an islanding event. I.e. low frequency initiates UFLS which should prevent an unintentional islanding event. The wording of this requirement makes it seem like the islanding event occurs first and causes the UF. **Response: The SDT modified Requirement R7 to clarify the intent of the UFLS database: Each Planning Coordinator shall annually maintain a UFLS database containing** ***data necessary to model its UFLS program for use in event analyses and assessments*** **of the UFLS program.**
MEAG Power	No	Developing a VSL tool similar to the VRF tool would be beneficial. The VSL seem arbitrary. For example, R1 has a "moderate" and "high" VSL if you do not take into account historical events when documenting and developing the criteria, but what if your sub-region never had an UF event? You are still in compliance?
Response: The SDT established the VSLs according to the VSL NERC guidelines. Requirement R1 requires that a Planning Coordinator consider historical events in establishing island criteria and does not require that they select islands based on historical islands that have formed.		
SPP System Protection and Control Working Group	No	For R11, the lower VSL is stated as a requirement and not as a VSL. Does it need to be reworded?

Organization	Yes or No	Question 3 Comment
Response: The SDT made conforming changes to the VSL for Requirement R11.		
Progress Energy - Carolinas	No	For R4, the VSLs should include a consideration of the timeliness of the completion of the required study (e.g. lower VSL for 3 months late, Moderate for 3-6 months late, etc.). **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary.** For the R11 VSLs, we recommend that the time ranges for the VSLs be expanded to allow more than one month between Low, Moderate, High and Severe. We would suggest revising to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months past the 12 month requirement. **Response: The SDT does not agree with the recommendation to add a range of time to the VSLs. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
Ameren	No	For Requirement R11, the 'Lower' VSL needs rewording. This VSL as written is just a repeat of the requirement text. Also, the time ranges for the VSL's should be expanded. Suggested ranges: Moderate: 12-14 months; High: 14-16 months; Severe: 16-18 months.
Response: The SDT made conforming changes to the VSL for Requirement R11. The SDT does not agree with the recommendation to add a range of time to the VSLs. The SDT established increments in the VSLs according to the VSL NERC guidelines.		
AECI	No	In R1 it is unclear how to use historical events and system studies to select portions of the BES. **Response: Requirement R1 requires that the Planning Coordinator consider historical events and system studies in selecting island criteria but the deliverable for Requirement R1 is a criteria for selecting islands and it doesn't require the entity to have island criteria based on historical events only to consider historical events.** In R4, I can see how we should be responsible for our own generators, but the information for generation owned by others is only as good as the data we receive. **Response: The SDT clarified in the Effective Date section of the standard that Requirement R4 is not effective until PRC-024 is approved and effective.** In R7 for the lower VSL, up to 40 days seems like it would include 30, should it be changed to say between 30 and 40? **Response: The SDT agrees with the commenter and made conforming changes to the VSL.**

Organization	Yes or No	Question 3 Comment
		In R11, for the lower VSL, it appears to be just a restatement of the requirement rather than a VSL. **Response: The SDT made conforming changes to the VSL for Requirement R11.**
MRO's NERC Standards Review Subcommittee (NSRS)	No	Most of the VSLs are okay. However, the VSLs for R5 and R13 depend on reaching "concurrence" with other entities, which is not a valid basis for measuring compliance. If the concurrence requirement is not revised as suggested below, then we propose that the VSL levels be reduced.
Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.		
Western Electricity Coordinating Council	No	R1 unclear definition of "criteria" it is never actually defined in the requirement. **Response: Requirement R1 requires that the Planning Coordinator consider historical events and system studies in selecting island criteria but the deliverable for Requirement R1 is criteria for selecting islands and it doesn't require the entity to have island criteria based on historical events only to consider historical events.** R2 For clarity Severe level should use the term "greater than 2" of the parts instead of "all" of the parts **Response: The SDT thinks that the intent is the same and did not make any conforming changes to the VSL for Requirement R2.** R3 For clarity Severe level should use the term "greater than 2" of the parts instead of "all" of the parts **Response: The SDT thinks that the intent is the same and did not make any conforming changes to the VSL for Requirement R2.** R4 no comment OKR5 very difficult to apply since Planning Coordinator footprints are not established. VSL could be based on number of adjacent PC's that do not concur. **Response: The SDT replaced "footprint" with "area" to be consistent with the Functional Model.** **The definition of the Planning Coordinator according to the Function Model version 5 states: The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.** **The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the**

Organization	Yes or No	Question 3 Comment
		Planning Coordinators coordinated should an island cross Planning Coordinator areas. R6 Not clear on what "annually maintain" means. Does it mean the Database requires annual updates, annual reviews or just the ability to provide a database annually? **The SDT modified Requirement R7 to clarify the intent of the UFLS database: Each Planning Coordinator shall annually maintain a UFLS database containing *data necessary to model its UFLS program for use in event analyses and assessments* of the UFLS program. Note that the team also revised Requirement R6 to provide greater clarity on the use of the word, 'annually.'** R7 at least some of the severity level should be based on the number of requests that were late rather than the time the request was overdue particularly since only an "annual maintenance" is required there is no difference in reliability impact if delivery is made in 30 or 60 days. **Response: FERC VSL guideline 4 (G4) states that a Violation Severity Level Assignment should be based on a single violation, not on a cumulative number of violations. Adopting the commenter's suggestion would violate this guideline.** R8 at least some severity level should be dependent on the lack of sufficiency of data as opposed to the amount of time it was overdue. **Response: FERC VSL guideline 4 (G4) states that a Violation Severity Level Assignment should be based on a single violation, not on a cumulative number of violations. Adopting the commenter's suggestion would violate this guideline.** R9 No comments I will assume the percentages have some basis and are not just arbitrary.R10 No comments I will assume the percentages have some basis and are not just arbitrary. **Response: Thank you for your comments.** R11 With respect to the VSLs I would recommend not combining the time duration and inclusion of parts. Use timing for lower and moderate and the lack of components for High and Severe. I have to be dumb here with the wording of the requirement. Does not the frequency excursion precede the islanding event. i.e. low frequency initiates UFLS which should prevent an unintentional islanding event. The wording of this requirement makes it seem like the islanding event occurs first and causes the UF This Requirement and VSL places emphasis on performing analysis and does not address any possible violation for actually having an inadequate UFLS program resulting in unintended islanding. **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary.** R12 VSL should be binary. Severe for failure to perform the assessment in the required time. Actually the

Organization	Yes or No	Question 3 Comment
		Requirement should be to "implement" the changes and correct the deficiencies not just to "consider" them in another assessment. If implementation were the focus the VSL's could be based on amount of implementation completed within a specified time frame. **Response: The SDT does not agree that the VSL for Requirement R12 should be a binary. The SDT thinks that the program is required to meet performance characteristics in Requirement R4. Requirement R12 requires that the Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. The timeliness of the assessment is an important element of the requirement and should be reflected in the VSLs.** R13 See comments for R5 with respect to PC footprint and also there is no clear indication of what is meant by event affecting other PC's does this mean islanding in the other areas or UF load shed or equipment switching? **Response: The SDT replaced "footprint" with "area" to be consistent with the Functional Model.** **The definition of the Planning Coordinator according to the Function Model version 5 states: The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.**
Y-W Electric Association, Inc.	No	Regarding the VSLs for R8, the UFLS entities cannot be punished for failing to meet a schedule if the schedule is not mutually agreed upon between the Planning Coordinator and the UFLS entities to ensure that the UFLS entities are capable of meeting such a schedule. At the very least, there must be some protection for the UFLS entities provided that requires the Planning Coordinator(s) to give the UFLS entities long-term notice of the deadlines that they will need to meet. The lack of any scheduling restrictions for the Planning Coordinators in the standard as written has a strong potential to cause enormous burdens on small UFLS entities that simply do not possess the resources to deal with such data reporting requirements without sufficient advance notice. Additionally, the UFLS entities cannot be penalized for failing to submit data in a format over which they have no control or input. The Planning Coordinator should be required to consult with the UFLS entities and decide upon a mutually agreeable data format in order to ensure that the UFLS entities are capable of providing the required data in the required format. With no language in the standard limiting or clarifying what data can be required of the UFLS entities by the Planning Coordinator, this provision at least should be made to protect small UFLS entities with highly limited resources for dealing with such data reporting requirements.
Response: The SDT added a requirement to the proposed standard, Requirement R14, to ensure that the Planning Coordinators collect and respond to		

Organization	Yes or No	Question 3 Comment
comments submitted by UFLS entities on the UFLS program, including a schedule for implementation and UFLS design assessment.		
Duke Energy	No	See comment to question #2 above.
Response: Please see our response to your comment to question #2.		
FirstEnergy	No	Since we do not agree with some of the standard requirements, we therefore do not agree with some of the VSL for the requirements as written.
Response: The SDT has made conforming changes to the proposed standard that addreses many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
IRC Standards Review Committee	No	The ability for the PC to comply with R1 and R2 requires ULFS entities and Transmission Owners to comply with this standard. The VSLs should clearly state that it is the PC who did not meet its obligations under R1 and R2 and not that non-compliance to R1 and R21 was the result of non-compliance by a third party which the PC relied on into meeting its obligations under this standard.
Response: The SDT is unclear as to how and why the Planning Coordinator needs to rely on the UFLS entities to comply with the requirements assigned to it. The SDT thinks that the Planning Coordinator can meet the obligations assigned to it in the proposed standard.		
Entergy Services	No	The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. **Response: The SDT made conforming changes to the VSL for Requirement R11.** Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented."The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.). **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
SERC Planning Standards Subcommittee	No	The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation.

Organization	Yes or No	Question 3 Comment
		Response: The SDT made conforming changes to the VSL for Requirement R11. Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe 16-18 months. **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
SERC SC UFLS Standard Drafting Team	No	The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. **Response: The SDT made conforming changes to the VSL for Requirement R11.** Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented."The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.). **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
Southern Company Transmission	No	The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. **Response: The SDT made conforming changes to the VSL for Requirement R11.** Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented."The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.). **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
Tennessee Valley Authority	No	The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a

Organization	Yes or No	Question 3 Comment
(TVA)		violation. **Response: The SDT made conforming changes to the VSL for Requirement R11.** Recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented."The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.). **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
Southern California Edison Company	No	We do not agree with the proposed reliability standard and, therefore, we cannot agree with the proposed Violation Severity Levels.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Pepco Holdings, Inc. - Affiliates	No	We do not concur with the requirements as written, so this activity is premature.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
American Transmission Co.	Yes	
Exelon	Yes	
IESO	Yes	
Indiana Municipal Power Agency	Yes	
Long Island Power Authority	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 3 Comment
MidAmerican Energy	Yes	
Northeast Power Coordinating Council	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst Engineering Staff	Yes	
South Carolina Electric and Gas	Yes	
Springfield Utility Board	Yes	
United Illuminating Company	Yes	
Northeast Utilities	Yes	Although NU agrees with the intent of the subject VSLs, we suggest that for Requirement R8 (Moderate and Severe) that the text beginning with OR is deleted. Additionally we suggest: o For Lower, Moderate and High VSLs - the first sentence be revised to read “The UFLS Entity provided data, in the format specified, to its Planning ...” o For Severe VSL - the first sentence be revised to read “The UFLS Entity failed to provide data, in the format specified, to its Planning Coordinator(s) within 20 calendar days ...”
Response: The SDT appreciates the formatting suggestions made by the commenter. The SDT thinks that they have accurately reflected the content of the Requirements in the associated VSLs.		
Wisconsin Electric Power Company (dba We Energies)	Yes	We agree with the Violation Severity Levels as far as the draft standard is currently written, however, see our comments for questions 11, 12, and 13 that would require modifications to requirements R9 & R10 and the corresponding Violation Severity Levels.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		

4. In the second posting, many of the requirements were assigned to groups of Planning Coordinators. These groups were to consist of all the Planning Coordinators within each of the Regional Entity footprints. The SDT has now revised these assignments to replace the groups with individual Planning Coordinators due to difficulties involved in assigning responsibilities to groups that do not currently exist. Do you agree with this revision?

Summary Consideration:

Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model version 5.

Commenters expressed confusion over having Transmission Owners as part of UFLS Entities but separated out as Transmission Owners in Requirement R10.The team reviewed the rationale for this structure and suggested merging Requirements R9 and R10. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements.

Organization	Yes or No	Question 4 Comment
GDS Associates	No	- Standard not entirely clear regarding to whom will apply (see 4.), groups or individual Planning Coordinators within the Regional Entity footprint.- Not sure what is the intent for paragraph 4.3
Response: The standard applies to individual Planning Coordinators, not groups. Applicability 4.3 is intended for Transmission Owners that may need to switch equipment other than load, such as shunt compensation to control over voltage.		
Wisconsin Electric Power Company (dba We Energies)	No	Although we agree that the Planning Coordinator has the wide-area view and technical skills to oversee the design of and ensure the effectiveness of a UFLS program, we are concerned with how this concept will actually play out, especially when a UFLS Entity is within multiple Planning Coordinators' footprints.
Response: In the case of a UFLS Entity in multiple Planning Coordinator footprints, that entity may need to set UFLS relays differently and may need to accommodate different schedules in the different footprints.		

Organization	Yes or No	Question 4 Comment
Tri-State Generation & Transmission Assoc.	No	Comments: Individual Planning Coordinators are not the entities to determine how islands should be formed, unless the Regional Assurer is required to become the only remaining Planning Coordinators, which would be acceptable. The current registration by numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. All Planning Coordinators within an interconnection should be required to collaboratively develop an Interconnection Coordinated UFLS Plan. UFLS works on interconnection basis not on PC footprint basis. We believe that the Regional Assurer will be better able to manage UFLS programs to the extent that the standard clearly lays out what must be accomplished. The primary purpose of any UFLS program is to mitigate the need to form islands by balancing total system loads and resources. It is only a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding events rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts within the interconnection. Again, we believe that the Regional Assurer will be better able to manage UFLS programs to the extent that the standard clearly lays out what must be accomplished We strongly believe that this should remain the responsibility of the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate or address the interconnection reliability needs.

Response: The SDT believes the Planning Coordinator, having a wide-area view and the necessary technical skills, is the proper entity to oversee the design and implementation of UFLS. There is also wide industry support for the Planning Coordinator as the proper entity for UFLS. The Reliability Assurer has a very limited scope of activity in the Functional Model and is not a user, owner or operator of the BES. The SDT recognizes the need to at least preserve coordination on the regional level and has inserted a requirement (Requirement R2, Part 2.3) to identify each Regional Entity footprint as an island to be assessed for UFLS performance. The PC's within each region will need to work with each other in order to produce a successful assessment.

The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.

Organization	Yes or No	Question 4 Comment
Exelon	No	Exelon does not agree with the concept of allowing neighboring Planning Coordinators to define or modify islanding criteria. There should be a single criteria for the determination of an island which is consistent across the interconnection, unless a specific geographic or regional exception is identified. Even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint.
Response: Neighboring Planning Coordinators cannot redefine or modify another Planning Coordinator's R1 island determination criteria. A Planning Coordinator may, however, select an island that overlaps a neighboring Planning Coordinator's footprint in complying with R2. A single criterion for island determination is not something that can be put into a continent-wide standard because many approaches to these criteria are likley to be acceptable.		
Bonneville Power Administration	No	It doesn't make sense to assign responsibilities to organizations that are not currently formed. Footprint or jurisdiction of Planning Coordinators has not been established and no mechanism exists for assigning a specific UFLS entity into a PC's jurisdiction. PCs within an interconnection should be required to develop an Interconnection Coordinated UFLS Plan. UFLS works on interconnection basis not on PC footprint basis. The purpose of the UFLS Plan is to mitigate the need to form islands by balancing loads and resources; a secondary function would be to balance the loads and resources after the islands have been formed. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts within the interconnection.
Response: The SDT agrees that responsibilities should not be assigned to organizations that are not currently formed. The SDT disagrees that the jurisdiction of Planning Coordinators and their footprints has not been established. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. **The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.**		
AECI	No	It is unclear what is meant by footprint if it is not a regional entity footprint. For those of us on a heavily interconnected border between two regional entities, do we now share a footprint with them? What about other utility's loads on our system, or vice versa, would we share a footprint with them as well? Also, R2.3 talks about if you are in multiple footprints, each of those footprints shall be identified as an island. Does that mean each footprint is a separate island or each footprint is included in the same big island?
Response: Planning Coordinators have footprints also. It is possible that a Distribution Provider or Transmission Owner can own equipment in two or		

Organization	Yes or No	Question 4 Comment
more Planning Coordinator footprints. If a utility is also a Planning Coordinator and has loads of another utility, also a Planning Coordinator, interspersed within its footprint, it may be best for both to un-register as Planning Coordinators and have a higher level entity register instead. **Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. There are no requirements to identify Planning Coordinator footprints as islands. The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs because Planning Coordinators within each Regional Entity footprint will need to coordinate with each other in order to produce successful UFLS design assessment for each regional island.**		
Entergy Services	No	R5 and R13 seem very problematic. The standard requires that both or all the entities agree. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two companies cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. R13 is not covered by R11 and cannot be eliminated; R13 is to R11 as R5 is to R4.		
SERC SC UFLS Standard Drafting Team	No	R5 and R13 seem very problematic. The standard requires that both or all the entities agree. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two companies cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among		

Organization	Yes or No	Question 4 Comment
Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. R13 is not covered by R11 and cannot be eliminated; R13 is to R11 as R5 is to R4.		
Southern Company Transmission	No	R5 and R13 seem very problematic. The standard requires that both or all the entities agree. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two companies cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. R13 is not covered by R11 and cannot be eliminated; R13 is to R11 as R5 is to R4.		
Ameren	No	Requirement R1 should be revised to read "Each Planning Coordinator, in coordination with its constituent Transmission Owners and Transmission Planners, shall develop and document criteria...". Further, it should include that the Regionla Entity should be involved in the studies, as in many cases, the RE has performed or were involved in thses studies. similarly, Requirement R2 should be revised to read "Each Planning Coordinator, in coordination with its constituent Transmission Owners and Transmission Planners, shall identify one or more islands...". Requirement R3 should be revised to read "Each Planning Coordinator, in coordination with its constituent Transmission Owners, Distribution Provider and Transmission Planners, shall develop a UFLS program..." The Planning Coordinator should in all UFLS related activities include UFLS plans and procedures which their Transmission Owner, Distribution Provider and Transmission Planners may have had in place, and functioning adequately, perhaps for many years.
Response: The SDT agrees that Transmission Owners and Transmission Planners should be involved in R1, R2 and in R3 along with Distribution Providers, but for compliance purposes, requirements must be clearly assigned to one specific entity. Adding the suggested phrase will cause confusion as to who is responsible to do what. The Functional Model description of Planning Coordinator includes coordination with other entities; the UFLS function should be expected to be added to the Planning Coordinator function once this standard is approved. Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES.		

Organization	Yes or No	Question 4 Comment
Progress Energy - Carolinas	No	Requirements R5 and R13 require Planning Coordinators (PCs) from two or more areas to agree on assessment results. However, no process is provided in the event that the PCs cannot agree. One party may have larger margin requirements or a different methodology and these differences may not be reconcilable. Therefore, it is possible that multiple PCs could be prevented from meeting the agreement requirement through no fault of their own. There needs to be a process for resolving this. We recommend that R5 include "If concurrence cannot be reached, an individual PC in the applicable island may demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply that PC's individual scheme to the entire island." Also, we recommend that R13 be deleted since R11 would effectively require these actions for multi-PC islands.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. R13 is not covered by R11 and cannot be eliminated; R13 is to R11 as R5 is to R4.		
Southern California Edison Company	No	SCE does not agree with this revision and supports WECC's position that "The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators."
Response: The SDT shares SCE's concern regarding further fragmentation of UFLS plans. The standard requires the identification of Regional Entity footprints as islands to be used in UFLS design assessments (Requirement R2, Part 2.3) and that the Planning Coordinators within each Regional Entity footprint work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within an interconnnection. The SDT believes that a continent-wide standard cannot require single UFLS plans for each interconnection. The degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; flexibility needs to be reserved to address regional needs. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design.		
Western Electricity Coordinating Council	No	The PCs within an interconnection should be required to coordinate a UFLS Design with all other PCs within the Interconnection and the PCs should be required to develop an Interconnection Coordinated UFLS Plan. UFLS works on interconnection basis not on PC footprint basis. The primary purpose of the UFLS Plan is designed to mitigate the need to form islands by balancing loads and resources. It is a secondary function to balance the loads and resources after the islands have been formed. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts

Organization	Yes or No	Question 4 Comment
		within the interconnection.From an audit and enforcement standpoint, no mechanism exists for assigning a specific UFLS entity into a PC's jurisdiction. This has the potential for making this standard unauditable for any entity which is not designated by a PC unless some guidance is established to determine a PC's footprint.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard requires the identification of Regional Entity footprints as islands to be used in UFLS design assessments (Requirement R2, Part 2.3) and that the Planning Coordinators within each Regional Entity footprint work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within an interconnnection. The SDT believes that a continent-wide standard cannot require single UFLS plans for each interconnection. **The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.** **The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design.** **The SDT disagrees that the jurisdiction of Planning Coordinators and their footprints has not been established. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities.**		
Xcel Energy	No	The problem still exits that the mapping of Planning Coordinators to 'subordinate' entities is not clear. Creating additional requirements for a functional entity that is still nebulous creates more confusion.We also believe the term "island" should be a defined NERC term. It is used throughout the standard with the meaning being generally understood within the industry but not explicitly stated.
Response: The SDT disagrees that mapping of Planning Coordinator footprints to UFLS Entities is not clear. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. **The SDT believes the term "island" to be readily understood and does not see a benefit of defining it in the NERC glossary even though its meaning in the industry is not the same as the dictionary definition.**		
Pepco Holdings, Inc. - Affiliates	No	The SDT has essentially defined groups by requiring concurrence.
Response: The SDT abandoned the group of Planning Coordinators concept because of compliance issues as stated in the background section. Concurrence was another method of gaining coordination among individual Planning Coordinators. (Note that the SDT has modified R5 and R13 to address concerns of other commenters on concurrence.) Without some level of cooperation among Planning Coordinators, further fragmentation of UFLS plans, which have been coordinated on a regional basis in the past, is likely. The SDT does not believe further fragmentation is in the interest of		

Organization	Yes or No	Question 4 Comment
reliability.		
American Transmission Co.	Yes	
FirstEnergy	Yes	
IESO	Yes	
Illinois Municipal Electric Agency	Yes	
Indiana Municipal Power Agency	Yes	
Long Island Power Authority	Yes	
Manitoba Hydro	Yes	
MEAG Power	Yes	
MidAmerican Energy	Yes	
Northeast Power Coordinating Council	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC Planning Standards Subcommittee	Yes	

Organization	Yes or No	Question 4 Comment
South Carolina Electric and Gas	Yes	
SPP System Protection and Control Working Group	Yes	
Tennessee Valley Authority (TVA)	Yes	
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
MRO's NERC Standards Review Subcommittee (NSRS)	Yes	Although THE NSRS agrees with changing the applicability of the requirements from groups of Planning Coordinators to each Planning Coordinator, the present wording in R2.3 says that for a PC with a part of its footprint in more than one region, "each of those Regional Entity footprints shall be identified as an island." We propose that the wording be revised to require a PC with part of its footprint in more than one region to identify only those appropriate parts of its area that are in islands, not the entire Registered Entity footprint where it may be present.
Response: The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. To this end, Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. These islands are to be used in UFLS design assessments and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. There are no requirements to identify Planning Coordinator footprints as islands, but all of a Coordinator's area will be included in one island or another.		
NERC Staff	Yes	NERC staff understands and supports this change to replace the groups with individual Planning Coordinators and agrees that it is a good hybrid approach. While NERC recognizes that the move might not be the ideal way to coordinate interregionally, at this point it does seem to be the best way to assign these requirements.
Response: Thank you for your support.		
Springfield Utility Board	Yes	There remains some abiguity with regards to the following language:"UFLS entities shall mean all entities that are responsible for the ownership,operation, or control of UFLS equipment as required by the UFLS programestablished by the Planning Coordinators. Such entities may include one or moreof the following:4.2.1 Transmission Owners4.2.2 Distribution Providers"SUB is fine with the Planning Coordinator

Organization	Yes or No	Question 4 Comment
		having the authority to determine UFLS requirements and affected entities. But there is a problem with regards implementation of a Planning Coordinator decides that equipment is required where it was not previously required by an entity. What is the process for the Planning Coordinator to provide notice to a registered entity (such as a Distribution Provider)? If a UFLS is required of a DP where a UFLS did not previously exist, what is the implementation plan for becoming compliant without having to be out of compliance on Day 1 just becuase a PC sent a letter?Under the implementation plan where it states:"The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time to develop or modify UFLS programs and to establish a schedule for implementation." Is this language intended for the PC to establish a schedule for implimentation of affected entities that fall under the standard after the standard is adopted?
Response: The SDT agrees that UFLS Entities should have opportunity to provide input to the Planning Coordinator on what will be required of them. R14 has now been added to the standard and requires a peer review of a Planning Coordinator's design and schedule for implementation by the UFLS Entities. **The Planning Coordinator has one year to come up with a design and schedule for implementation, but the UFLS Entities are subject only to the Coordinator's schedule according to R9, not this one year phase-in.**		
IRC Standards Review Committee	Yes	We agree; however, this standard should not disallow the ability for some PCs to group together to develop a wide area UFLS plan. To the extent some PCs do this, the standard should be written and performance measured in a manner that does not cause these PCs to duplicate the same documents that may already be provided by another PC for the same footprint.
Response: Each individual Planning Coordinator is subject to compliance. The group concept was abandoned to avoid complaince issues as mentioned in the background section. The standard does not disallow voluntary groupings of Planning Coordinators, but each Planning Coordinator would still be responsible for its own compliance.		
Duke Energy	Yes	Yes, except for the issue on "reaching concurrence" identified in our response to question #2 above (R5 and R13).
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern.		

5. Several commenters indicated in the second posting potential conflicts and redundancies between PRC-006-1 and EOP-003-1 requirements. The SDT agrees that EOP-003-1 contains requirements that are redundant and/or conflict with the proposed requirements in PRC-006-1. The SDT sought approval to post a supplemental SAR to include EOP-003-1 Underfrequency Load Shedding related requirements in the scope of the UFLS SDT. The SC agreed to post the SAR with a proposal to revise the original scope of the UFLS SAR and the SDT revised the EOP-003-1 requirements to remove the conflicts.

Summary Consideration:

While the standard drafting team received support for the changes to EOP-003 eliminating the redundancy between it and PRC-006 related to underfrequency load shedding requirements, some commenters indicated that the standard drafting team should clarify that the remaining requirements in EOP-003 are related to automatic undervoltage load shedding and manual under frequency load shedding. The drafting team made a conforming change to the proposed standard to clarify that the requirements exclude automatic underfrequency load shedding by adding the following phrase to Requirements R3 and R5: excluding under-frequency load shedding plans

Other comments received indicated that the standard drafting team should revise the requirements related to undervoltage load shedding; however, there is a NERC project tasked with revising EOP-003 and while it is at the initial stages this team will address the requirements that require revision. In addition, the Supplemental SAR approved by the Standards Committee limits the scope to removing conflicts and redundancies related to under-frequency load shedding only in EOP-003-1.

Organization	Yes or No	Question 5 Comment
Xcel Energy		No comments
ReliabilityFirst Engineering Staff		No response seems applicable.
MidAmerican Energy	No	The SAR needs to recognize that all the standards are interconnected and other existing standards development. Automatic load shedding needs to be left in PRC-006. Manual load shedding should be left in EOP-003 according to already existing standards proposed changes. The SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and referring them to a new UVLS standard or PRC-006.
Response: The Supplemental SAR approved by the Standards Committee limits the scope to removing conflicts and redundancies related to under-frequency load shedding only in EOP-003-1.		

Organization	Yes or No	Question 5 Comment
Ameren	Yes	
American Transmission Co.	Yes	
Duke Energy	Yes	
Exelon	Yes	
IESO	Yes	
IRC Standards Review Committee	Yes	
Long Island Power Authority	Yes	
MEAG Power	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Progress Energy - Carolinas	Yes	
South Carolina Electric and Gas	Yes	
Southern California Edison Company	Yes	
SPP System Protection and Control Working Group	Yes	
Springfield Utility Board	Yes	
Tennessee Valley Authority	Yes	

Organization	Yes or No	Question 5 Comment
(TVA)		
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
Indiana Municipal Power Agency	Yes	IMPA agrees with these actions.
Wisconsin Electric Power Company (dba We Energies)	Yes	See comments for question 6 and 7.
Western Electricity Coordinating Council	Yes	This really doesn't look like a question, and it appears the actual question is asked in number 6.
FirstEnergy	Yes	While we agree with the inclusion of the EOP-003 in this project, the versioning and requirement language adjustments requires coordination with the proposed revision of EOP-003 that is taking place with the Order 693 Directives work Project 2010-12.
Response: The scope of work addressed under the Order 693 Directives was revised so that Project 2010-12 no longer addresses EOP-003.		

6. Do you agree with the expanded scope in the Supplemental SAR?

Summary Consideration:

While the standard drafting team received support for the changes to EOP-003 eliminating the redundancy between it and PRC-006 related to underfrequency load shedding requirements, some commenters indicated that the standard drafting team should clarify that the remaining requirements in EOP-003 are related to automatic undervoltage load shedding and manual under frequency load shedding. The drafting team made a conforming change to the proposed standard to clarify that the requirements exclude automatic underfrequency load shedding.

Other comments received indicated that the standard drafting team should revise the requirements related to undervoltage load shedding; however, there is a NERC project tasked with revising EOP-003 and while it is at the initial stages this team will address the requirements that require revision.

Organization	Yes or No	Question 6 Comment
Xcel Energy		No comments
IRC Standards Review Committee	No	Please see comments to 7.
MidAmerican Energy	No	The SAR needs to recognize that all the standards are interconnected and other existing standards development. Automatic load shedding needs to be left in PRC-006. Manual load shedding should be left in EOP-003 according to already existing standards proposed changes. The SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and referring them to either a new UVLS standard or PRC-006
Response: There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
American Transmission Co.	No	We propose that the scope of the SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for also removing the automatic UVLS requirements from EOP-003-1 and referring them to a new PRC standard.
Response: There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	No	We propose that the scope of the SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and moving them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and moving them to a new PRC standard
Response: There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	We propose that the scope of the SAR be revised to call for removing all of the automatic UFLS requirements from EOP-003-1 and moving them to PRC-006-1 standard because no automatic load shedding system requirements should be in the EOP standards. We also note that a separate SAR should be initiated to call for the removal of all the automatic UVLS requirements from EOP-003-1 and moving them to a new PRC standard for the same reason.
Response: There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
Ameren	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Entergy Services	Yes	
Exelon	Yes	
IESO	Yes	
Indiana Municipal Power Agency	Yes	
Long Island Power Authority	Yes	
MEAG Power	Yes	

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Progress Energy - Carolinas	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC Planning Standards Subcommittee	Yes	
SERC SC UFLS Standard Drafting Team	Yes	
South Carolina Electric and Gas	Yes	
Southern Company Transmission	Yes	
SPP System Protection and Control Working Group	Yes	
Tri-State Generation & Transmission Assoc.	Yes	
United Illuminating Company	Yes	
Western Electricity Coordinating Council	Yes	

Organization	Yes or No	Question 6 Comment
Y-W Electric Association, Inc.	Yes	
NERC Staff	Yes	NERC staff agrees that it is wise to revise requirements specific to Underfrequency Load Shedding in EOP-003-1 to remove inconsistencies and redundancies. The only concern is that because both ad hoc team for expediting certain standards processes and the original EOP-003-1 SDT are working on modifications to the standard, there could be some overlap and miscommunication, especially with respect to these redundancies between PRC-006-1 and EOP-003-1.
Response:The Order 693 Directives team has removed revisions to EOP-003-1 from the scope of its project.		
Tennessee Valley Authority (TVA)	Yes	TVA supports this direction to remove the automatic load shedding components (UFLS and UVLS) from EOP-003 to avoid potential conflict with the PRC standards that address UFLS and UVLS.
Response: Thank you for your supportive comment.		
Southern California Edison Company	Yes	We agree in principle with the expanded scope for the Supplemental SAR.
Response: Thank you for your supportive comment.		
Wisconsin Electric Power Company (dba We Energies)	Yes	We agree with the expanded scope of the supplemental SAR, however, EOP-003-1 needs further revision to focus this standard solely on manual loadshed. References to the development of both UFLS and UVLS programs need to be removed from EOP-003-1 as PRC-006-1 will cover automatic UFLS programs and a series of other PRC standards already cover automatic UVLS programs. The SDT should delete R2, R4, R7 and M1 from the posted SDT revised draft standard EOP-003-1 as part of supplemental SAR limited scope of revising requirements related to underfrequency loadshedding. In addition, the SDT should give consideration to inserting the word “manual” in front of the words “load shedding” in R3 and R5 in the posted SDT revised draft standard EOP-003-1. The Measures and Violation Severity Level sections would need to be updated accordingly.
Response: The drafting team made a conforming change to the proposed EOP-003-1 standard to clarify that the requirements exclude automatic underfrequency load shedding. Removing references to UVLS from EOP-003-1 goes beyond the scope of the supplemental SAR.		
FirstEnergy	Yes	While we agree with the inclusion of the EOP-003 in this project, the versioning and requirement language adjustments requires coordination with the proposed revision of EOP-003 that is taking place with the Order

Organization	Yes or No	Question 6 Comment
		693 Directives work Project 2010-12.
Response: The project related to Order 693 directives has pulled the EOP-003 standard.		

7. Do you agree with the revisions to EOP-003-1?

Summary Consideration:

While the standard drafting team received support for the changes to EOP-003 eliminating the redundancy between it and PRC-006 related to underfrequency load shedding requirements, some commenters indicated that the standard drafting team should clarify that the remaining requirements in EOP-003 are related to automatic undervoltage load shedding and manual under frequency load shedding. The drafting team made a conforming change to the proposed standard to clarify that the requirements exclude automatic underfrequency load shedding.

Other comments received indicated that the standard drafting team should revise the requirements related to undervoltage load shedding; however, there is a NERC project tasked with revising EOP-003 and while it is at the initial stages this team will address the requirements that require revision.

Organization	Yes or No	Question 7 Comment
Western Electricity Coordinating Council		Agree with the removal of the words underfrequency and Balancing Authority in EOP-003, but do not agree with the EOP-003-1 or the current version of EOP-003-2 that is out for vote because it still includes automatic UFLS. EOP-003-2 should include reference to manual load shed only. It includes UFLS that is undefined and could cause a conflict with PRC-006.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
MEAG Power		No comment.
Xcel Energy		No comments
Southern California Edison Company		We cannot comment on the proposed revisions to EOP-003-1, as their ramifications have not been studied in detail.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
Long Island Power Authority	No	
Wisconsin Electric Power	No	Although we agree with the intent of the revisions, EOP-003-1 needs further revision to focus this standard solely on manual loadshed. References to the development of both UFLS and UVLS programs need to be

Organization	Yes or No	Question 7 Comment
Company (dba We Energies)		removed from EOP-003-1 as PRC-006-1 will cover automatic UFLS programs and a series of other PRC standards already cover automatic UVLS programs. The SDT should delete R2, R4, R7 and M1 from the posted SDT revised draft standard EOP-003-1 as part of supplemental SAR limited scope of revising requirements related to underfrequency loadshedding. In addition, the SDT should give consideration to inserting the word "manual" in front of the words "load shedding" in R3 and R5 in the posted SDT revised draft standard EOP-003-1. The Measures and Violation Severity Level sections would need to be updated accordingly.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
MidAmerican Energy	No	Automatic load shedding needs to be left in PRC-006. Manual load shedding should be left in EOP-003 according to already existing standards proposed changes. The SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and referring them to a new PRC-024-1 standard. In line with the comments for Question 6:R2 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and PRC-024-1.R3 - add the qualification "coordinate manual load shedding plans".R4 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and PRC-024-1.R5 - add the qualification "implement manual load shedding plans".R7 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and PRC-024-1
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
Ameren	No	Because EOP-003-1 is the primary load shedding standard, and because UFLS has been removed from EOP-003-1 and placed in PRC-006-1, standard EOP-003-1 should note in the "Purpose" section that UFLS is addressed in PRC-006-1.The stated purpose of EOP-003-1 is to have the capability and authority to shed load rather than risk uncontrolled failure of the interconnection if there is insufficient generation or transmission capacity. It is not clear when and how it is determined that an "automatic" load shedding scheme is necessary or required. Are all TO's required to have undervoltage load shedding plans in place? Suggest changing the ending phrase of R2 in EOP-003 from "required" to "necessary to minimize the risk of uncontrolled failure of the Interconnection." Also suggest a review of other UVLS stanadrds for consistency with revised EOP-003.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-		

Organization	Yes or No	Question 7 Comment
frequency load shedding.		
SERC Planning Standards Subcommittee	No	Because EOP-003-1 is the primary load shedding standard, and because UFLS has been removed from EOP-003-1 to PRC-006-1, standard EOP-003-1 should note in the "Purpose" section that UFLS is addressed in PRC-006-1.Suggest changing the ending phrase of R2 in EOP-003 from "required" to "necessary to minimize the risk of uncontrolled failure of the Interconnection."
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
Tri-State Generation & Transmission Assoc.	No	Comments: The revisions are adequate for the most part, but Requirement R4 needs to specify that only undervoltage load shedding is being addressed.There is also a concern that EOP-003-2 is currently being balloted based on changes made as a part of the Order 693 Directives. The two versions are not compatible.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. The project related to Order 693 directives has removed EOP-003 revisions from its scope of work.		
Bonneville Power Administration	No	EOP-003-1 and the current version of EOP-003-2 still include automatic UFLS. EOP-003-2 should include reference to manual load shed only. To include UFLS that is undefined would cause a conflict with PRC-006.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
Exelon	No	EOP-003-1 needs to define the criteria as to when and how UVLS schemes are installed to provide consistency direction to Planning Coordinators and the entities that have to install UVLS schemes. The relationship between the use of UVLS and compliance with TPL-001 standards should be clarified. Is load shedding (including UVLS) allowed to meet the performance criteria in TPL-001? The standard should define when UVLS are applicable to the BES and thus subject to the requirements of EOP-003. UVLS schemes developed for distribution or other purposes beyond criteria should not be discouraged through regulatory burden.UVLS should be carefully defined. Many types of load will cut out on low voltage.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
American Transmission Co.	No	In line with the comments for Question 6:R2 - remove this requirement because it refers to automatic load

Organization	Yes or No	Question 7 Comment
		shedding plans, let this be covered by PRC-006-1 and new PRC standard.R3 - add the qualification "coordinate manual load shedding plans".R4 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.R5 - add the qualification "implement manual load shedding plans".R7 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
Manitoba Hydro	No	In line with the comments for Question 6:R2 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.R3 - add the qualification "coordinate manual load shedding plans".R4 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.R5 - add the qualification "implement manual load shedding plans".R7 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	In line with the comments for Question 6:R2 - remove this requirement because it refers to automatic load shedding plans and let the automatic requirements be covered by PRC-006-1 and a new PRC standard.R3 - Recommend R3 be rewritten to read: Each Transmission Operator and Balancing Authority shall provide manual load shedding plans to adjacent interconnected Transmission Operators and Balancing Authorities.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
United Illuminating Company	No	R1 should use term "shall implement manual load shedding". The Drafting team note says that PRC-006 is a Planning Standard and therefore EOP-003 R1 is needed to apply to the actual implementation of automatic load shed. We disagree that PRC-006 is solely Planning. The UFLS entity is required to implement the program, meaning protective devices are deployed and armed. By creating the program and arming the protection systems the UFLS Entity has committed to load shed.EOP-003 R1 is addressing the steps or actions a Transmission Operator takes to respond to insufficient resources. The Transmission Operator does

Organization	Yes or No	Question 7 Comment
		not initiate automatic UFLS.The UFLS program is created by the Planning Coordinator and implemented by Transmission Owners and DP. EOP-003 requires the BA and TOP to perform load shed. Again, for UFLS this implies the TOP and BA have on/off control for UFLS protection systems. This we know is not true. The TOP/BA has the authority to implement manual load shed.A similar argument is made for R3. R3 should be "coordinate manual load shed plans". Coordinating plans is a Planning Horizon exercise. Therefore EOP-003 R3 coordination of ufls load shed by TOP/BA is a duplicate function to the PRC-006 coordination by Planning Coordinators. The entity with the best knowledge to coordinate UFLS is the Planning Coordinator. TOP and BA are coordinating the manual load shed plan with the recognition the UFLS is installed.In R5 add the words "automatic load shedding scheme other than UFLS". This will help compliance monitoring by explicitly differentiating this from PRC-006. Update the VSL also with this clarification.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
Western Area Power Administration	No	R2 thru R5 - is specific to under voltage conditions but the "Purpose" of the standard states is for insufficient generation along with insufficient xmsn capacity. Also the Transmission Operator does not establish plans or coordinate for auto load shedding for under voltage conditions - this is a function of PlanningR6 and R7 - now the requirements are back to under frequency along with under voltage. R8 - states the Operator shall be capable of implementing load shed adequate for responding to the EM - in most cases there is not enough time to respond manually. Is this referencing if a condition develops slowly enough to have time to respond?Seems like the purpose and requirements should be further defined so that EOP-003 is specifically for BA and Transmission Operations for developing low voltage/frequency conditions with ability/authority to shed load and PRC-006 for Planning defining auto load shed for low voltage/frequency conditions.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
Pepco Holdings, Inc. - Affiliates	No	R2.3 appears to require a PC that is involved in more than one region to have an "islanding program" for its footprint in each region. What if the PC is PJM and there is a sliver a region outside RFC. Do we really need a program for the sliver? This requirement assumes without justification that RE boundaries and PC boundaries define potential islands. **Response: The intent with this approach is to ensure coordination between regions and for selecting islands that overlap adjacent regions within an interconnection.** R4 - What is a "design assessment"? Why not just require "an assessment every five years"? Why all the

Organization	Yes or No	Question 7 Comment
		extra words like "design assessment"? "conduct and document"? through dynamic simulations? **Response: The SDT thinks that the added words clarify the intent of the requirements.** R5 requires concurrence among PCs. My view is that a requirement must be to one and only one functional entity. More than one entity causes questions as to who is non-compliant when things go awry. In R5 who is non-compliant if a peer PC does not concur? **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern.** R6 Why not just require a database for UFSL data? Why must the requirement include the editorial requirement "for use in Event Analysis and assessments of UFLS program" Does that mean I MUST use the UFLS database for Event Analysis? Does it mean I can't use the data for other activities?R8 is curious to me. It stipulates that the data is provided "to support the database". I ask, isn't the data being required to support the concept that the UFLS program is up-to-date and operational? For both R6 and R8, the issue is editorial explanations in addition to the actual requirement. **Response: The SDT thinks that the added words clarify the intent of the requirements.** R12 seems to say that PC whose assessment shows a problem, that PC shall conduct an assessment (again?). The requirement then goes on to mandate the PC "consider" the deficiencies. I know what they want to say but this requirement doesn't say it to me. Can you imagine proving you "considered the deficiencies"? **Response: PRC-009 contains an assessment requirement after the actuation of UFLS.**
AECI	No	R4 says voltage or power flow levels must be considered when designing an automatic load shedding scheme. Our UFLS scheme is an automatic load shedding scheme that does not take voltage or power flow levels into account. R4 needs to be reworded so that it is clear that it is ok to have automatic UFLS schemes that do not rely on under voltage or power flow levels.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
Tennessee Valley Authority (TVA)	No	TVA supports the modifications to the EOP-003 standard which remove UFLS. We believe that EOP-003 should continue to be revised under the appropriate project to focus the emphasis on load shedding plans that are controlled by operator action, and exclude automatic protection schemes (UFLS and UVLS) that do not require operator action to execute their designed function.We have the following comments on the proposed modifications:R2 - We recommend that the text added at the end of this requirement be removed (“if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s)

Organization	Yes or No	Question 7 Comment
		determine that an under-voltage load shedding scheme is required."). This addition introduces entities that are not identified in the "Applicability" section of the standard (A.4). While simulations performed in the planning environment (TPL standards) would likely lead to this determination, references to the Transmission Planner and Planning Coordinator in this requirement will introduce compliance confusion. Can the SDT point to another standard that requires the Transmission Planner or Planning Coordinator to determine if an under-voltage load shedding scheme is required? Our preference would be to strike requirement R2 from the EOP-003 standard altogether, but we realize the scope of this project is limited to UFLS.R4 - With the deletions that are being proposed, we recommend that "undervoltage" be inserted into the requirement for clarification -- "automatic undervoltage load shedding scheme".R7 - Since the Balancing Authority has been removed, suggest changing "their areas" to "their area" (singular).
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. The Supplemental SAR approved by the Standards Committee limits the scope to removing conflicts and redundancies related to under-frequency load shedding only in EOP-003-1.		
IRC Standards Review Committee	No	We understand the concerns that EOP-003-1 contains redundant requirements. However, the Order 693 changes include revisions to EOP-003-1 that are in conflict with the supplemental SAR.
Response: The project related to Order 693 directives has removed EOP-003 from the scope of its project.		
Duke Energy	Yes	
Entergy Services	Yes	
IESO	Yes	
Oncor Electric Delivery	Yes	
Progress Energy - Carolinas	Yes	
SERC SC UFLS Standard Drafting Team	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 7 Comment
Southern Company Transmission	Yes	
SPP System Protection and Control Working Group	Yes	
Y-W Electric Association, Inc.	Yes	
FirstEnergy	Yes	Although we agree with the revisions to EOP-003 with regard to removal of underfrequency load shedding references, we believe the SDT could have improved the standard even further by developing a complete set of measures. There are currently only two measures for eight requirements. Furthermore, since EOP-003-1 is the current approved standard, and this standard would be version 2 (EOP-003-2).
Response: Thank you for your support. The standard drafting team does not think the Measures need to be modified as the team has only eliminated any inference to underfrequency load shedding in the requirements and performed a review of the Measures and determined they do not need revision.		
Northeast Power Coordinating Council	Yes	EOP 003 is on the list of standards identified by the NERC Tiger Team for fast tracking of Order 693 directives. There is concern that coordination between these two DT's may not have occurred and that the changes agreed upon in the revised UFLS SAR should also be considered by the Tiger Team.
Response: : The project related to Order 693 directives has removed EOP-003 from the scope of its project.		
Northeast Utilities	Yes	EOP 003 is on the list of standards identified by the NERC Tiger Team for fast tracking of Order 693 directives. There is concern that coordination between these two DT's may not have occurred and that the changes agreed upon in the revised UFLS SAR should also be considered by the Tiger Team.
Response: : The project related to Order 693 directives has removed EOP-003 from the scope of its project.		
Indiana Municipal Power Agency	Yes	However, changes need to be coordinated with the tiger team and their changes to EOP-003-1.
Response: : The project related to Order 693 directives has removed EOP-003 from the scope of its project.		
NERC Staff	Yes	NERC staff agrees that it is wise to revise requirements specific to Underfrequency Load Shedding in EOP-003-1 to remove inconsistencies and redundancies. The only concern is that because both the team of experts (formerly known as the Tiger Team) and the original EOP-003-1 SDT are working on modifications to

Organization	Yes or No	Question 7 Comment
		the standard, there could be some overlap and miscommunication, especially with respect to these redundancies between PRC-006-1 and EOP-003-1.
Response: : The project related to Order 693 directives has removed EOP-003 from the scope of its project.		
ReliabilityFirst Engineering Staff	Yes	Yes, the revisions that were made are appropriate. However, EOP-003 will require further substantial revisions as many of the requirements are still inappropriately assigned to the TOP such as establishing automatic undervoltage load shedding plans (R2).
Response: There is a NERC project tasked with revising EOP-003 and while it is at the initial stages this team will address the requirements that require revision. The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. The Supplemental SAR is focused solely on eliminating redundancies between the two standards related to underfrequency load shedding.		

8. Based on industry supplied comments, the SDT modified the applicability of the standard from "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" and "Distribution Providers" in the second posting to "UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include Transmission Owners and/or Distribution Providers" in an effort to more appropriately identify those entities responsible for providing UFLS coverage. Has the SDT correctly identified the proper entities for UFLS coverage?

Summary Consideration:

Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.

Organization	Yes or No	Question 8 Comment
The California ISO	No	1) Applicability of the proposed Standard PRC-006-1 should also apply to Load Serving Entities (LSEs) for underfrequency load shedding.2) Applicability of the proposed Standard PRC-006-1 should also apply to Generator Owners since GOs would need to be involved for overfrequency generation tripping.3) Applicability of the proposed Standard PRC-006-1 should also apply to the Reliability Assurer/Regional Reliability Organization (RRO). (WECC in our case).4) The Reliability Assurer/Regional Reliability Organization (RRO) should be the entity that coordinates the UFLS programs.
Response: 1)The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons." **2) The responsibility of generator owners resides within a standard under development currently, PRC-024. Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.** **3) Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES. This standard is under development as a direct result of this particular issue and was identified as a part of a set of standards for having "fill in the blank" requirements. The SDT has crafted Requirements R5 and R13 to allow for and encourage coordination among**		

Organization	Yes or No	Question 8 Comment
PCs. This standard does not preclude the RRO/RA from performing this coordination function, but does not include a requirement for the RRO/RA for this purpose. **4) This option is not precluded from the standard as it is written. However, ultimate responsibility for developing UFLS programs lies with the Planning Coordinators.**		
Entergy Services	No	1. We recommend that R3 be revised to require the PC to specifically notify the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. **Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.** 2. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information. **Response: Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.**
Y-W Electric Association, Inc.	No	Because Load Serving Entities (not Distribution Providers) are actually responsible for the load in the current Functional Model and Compliance Registry Criteria, they should also be included in the applicability section of this standard.
Response: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.		
Tri-State Generation & Transmission Assoc.	No	Comments: We believe that "ownership" should be removed from the criteria because it may be different from the operating or controlling entity and both entities cannot be responsible. **Response: The SDT's intent was to adequately capture the entities which "own, operate or control" UFLS equipment. In the sense it is written here, 'control' of the relay setpoints is the critical distinction as the relays operate once a predetermined set of system conditions has been achieved.**

Organization	Yes or No	Question 8 Comment
		Load Serving Entities should also be included as a "possible" UFLS entity Some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. **Response: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons** This should remain the responsibility of the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate nor address the interconnection reliability needs. **Response: Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES. This standard is under development as a direct result of this particular issue and was identified as a part of a set of standards for having "fill in the blank" requirements. The SDT has crafted Requirements R5 and R13 in order to allow for and encourage coordination among PCs. This standard does not preclude the RRO/RA from performing this coordination function, but does not include a requirement for the RRO/RA for this purpose.**
IRC Standards Review Committee	No	Generator owners are not included in the applicability of this standard. We understand from the SDT's responses to the last posting that there is a separate project for generator requirements that could obligate them to provide required data to planning coordinators for underfrequency load shedding schemes. However, absent that standard, a generator owner has no obligation to provide needed data to a planning coordinator. If the generator owner fails to provide that data, then that planning coordinator could be found in violation of a requirement in PRC-006-1. NERC must recognize that registered entities may vote against PRC-006-1 if they are concerned about the ability to meet requirements which rely on yet to be approved or developed standards and/or definitions. Therefore, in a concerted effort to move proposed standards through the approval process, NERC must not enforce specific requirements upon a registered entity if that entity cannot meet a requirement because a supporting standard or definition is not yet in effect. **Response: GO applicability lies within the PRC-024 standard currently under development. Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not**

Organization	Yes or No	Question 8 Comment
		come into effect until after PRC-024 is approved. We are also concerned that the ULFS standards requirements may not apply to new entities and loads that may be interconnected to the BPS such as those for Demand Response grid services. New technologies such as Smart Grid and Plug-In Electric Vehicles will become more prevalent in the near future and new entities may be aggregating these loads to offer grid services. Because it is unknown how these aggregators may be structured, they may not fall into the registered entity categories specified in this standard. NERC should be diligent in identifying new entities that existing approved standards should apply to and adjust the registry and standards accordingly. **Response: Thank you for your comment.**
IESO	No	Generator owners are not included in the Applicability Section of this standard. We understand from the SDT's responses to the last posting that there is a separate project for generator requirements that would obligate them to provide the required information to the Planning Coordinators with which to design the underfrequency load shedding program. Absent that standard, a Generator Owner has no obligation to provide the necessary data to the Planning Coordinators which can result in the Planning Coordinator failing to meet the PRC-006-1 standard. We therefore request that Generator Owner be included in the Applicability Section and a requirement for it to provide the needed information to the Planning Coordinator be added, or balloting of standard PRC-006-1 be deferred until such a requirement in that other standard is ready for balloting. **Response: GO applicability lies within the PRC-024 standard currently under development. Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.** The reason for including Transmission Owners in Section A 4.3 after they have been identified in Section A 4.2 is unclear or not needed. **Response: The SDT added this additional distinction for the purposes stated in Requirement R10. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.**
AECI	No	It seems like generator owners should be added here, especially since R4 deals with generator frequency settings
Response: GO applicability lies within the PRC-024 standard currently under development. Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.		

Organization	Yes or No	Question 8 Comment
Bonneville Power Administration	No	LSE should also be included as a "possible" UFLS entity some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. **Response: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.** In addition to the issue previously stated concerning PC authority, no valid way exists to determine which registered entities are under the jurisdiction and authority of any Planning Coordinator. The current version does not address customer-owned UFLS relays. There should be recognized sub-area group(s), which consists of PCs, as assigned by the Regional Assurer (RA) which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off-Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate nor address the interconnection reliability needs. **Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES. This standard is under development as a direct result of this particular issue and was identified as a part of a set of standards for having "fill in the blank" requirements. The SDT has crafted Requirements R5 and R13 in order to allow for and encourage coordination among PCs. This standard does not preclude the RRO/RA from performing this coordination function, but does not include a requirement for the RRO/RA for this purpose.**
Western Electricity Coordinating Council	No	LSE should also be included as a "possible" UFLS entity Some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. **Response: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.** There should be a recognized sub-area group(s), which consist of PCs, as assigned by the Regional Assurer

Organization	Yes or No	Question 8 Comment
		(RA) which is the agent(s) for overall coordination within the interconnection or sub-area. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate nor address the interconnection reliability needs. **Response: Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES. This standard is under development as a direct result of this particular issue and was identified as a part of a set of standards for having "fill in the blank" requirements.**
Tennessee Valley Authority (TVA)	No	Our preference is that the applicability section of the standard remain "clean" with regard to the applicable entities listed, and not cluttered with qualifiers. For instance, we see no benefit in listing Transmission Owners twice (4.2.1 and 4.3).If this format is retained, we suggest that section 4 be revised to add clarity. We suggest that section 4.2 be revised to read:"UFLS entities shall mean all entities that are responsible for the ownership, design, or installation of UFLS equipment or automatic switching of Elements as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers"and that 4.3 be deleted. **Response: The SDT added this additional distinction for the purposes stated in Requirement R10. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** The terms "operation" and "control" are typically used in the context of an operating entity task (RC, TOP, GOP, BA). Therefore we prefer the use of "ownership, design, and installation" over "ownership, operation, or control". **Response: The SDT intent was to adequately capture the entities which "own, operate or control" UFLS equipment. In the sense it is written here, 'control' of the relay setpoints is the critical distinction as the relays operate once a predetermined set of system conditions has been achieved.** The omission of the Generator Owner from this standard is potentially problematic in that coordination with generator under- / over-frequency settings is needed. **Response: Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.** We also note that PRC-008-0 contains the phrase "required by its Regional Reliability Organization to have a UFLS program". Should this be changed to "required by its Planning Coordinator to have a UFLS program" to align with the proposed changes to PRC-006-1? **PRC-008 will be addressed as a part of project 2007-17, Protection System Maintenance and Testing,**

Organization	Yes or No	Question 8 Comment
		which is currently out for ballot. Lastly, with the modifications to EOP-003, there is no linkage of operating entity applicability to UFLS. While beyond the scope of this drafting team's objectives, we believe that operator awareness of UFLS installations is a critical component of load restoration following an event that initiates UFLS tripping. **FERC order 693 is directing the changes to EOP-003. Also, operator action during system restoration typically occurs well after UFLS has attempted to arrest frequency decline during an underfrequency event.**
Southern California Edison Company	No	SCE agrees with WECC's position that "the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered, the LSE needs to be included in the Applicability section".
Response: The SDT recognizes that the Functional Model version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.		
Northeast Power Coordinating Council	No	Significant amounts of UFLS capability may fall outside the current FM design, and the DT is trying to capture all entities that control UFLS in its applicability requirements. In spite of this effort ambiguity still exists in the applicability regarding the broad statement pertaining to UFLS entities that 'control' UFLS equipment.
Response: The SDT intent was to adequately capture the entities which "own, operate or control" UFLS equipment. In the sense it is written here, 'control' of the relay setpoints is the critical distinction as the relays operate once a predetermined set of system conditions has been achieved. **In an effort to remove some ambiguity in this regard, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.**		
MidAmerican Energy	No	The word "all" should be replaced with "applicable". The compliance requirement should focus on primary entity identified responsible for that compliance function. An example, might include a jointly owned facility (generator, substation, line, transformer, or capacitor bank) owned by one or more entities and operated by another. One identified entity should be identified and held responsible its UFLS relays whether through majority ownership, interconnection agreements, or contracts. Since ownership and operation can be divided, it is inappropriate to enforce compliance responsibilities on entities outside of their control.

Organization	Yes or No	Question 8 Comment
Response: The SDT cannot comment on contractual issues, however, in an effort to remove some ambiguity regarding UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.		
Xcel Energy	No	We question why Generator Owners are not included as a UFLS entity. Under R4 PCs are required to obtain setting from them. We are not aware of another standard that requires GOs to provide those settings to the PC. Thus there should also be a requirement indicating that GOs (or UFLS Entities) provide data requested by the PC to conduct the required assessments.
Response: Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.		
FirstEnergy	No	We support the applicability section of the standard as asked per this question. However, we do not see any question for general comments and have comments and suggestions regarding the proposed implementation plan for the applicable UFLS entities and Transmission Owners that own Elements identified in the UFLS program. 1. Although we agree that the Planning Coordinator is the appropriate functional entity to develop and implement a UFLS program, we are concerned with the fact that UFLS entities may not know the specifics of their responsibilities until long after this standard is approved. The SDT should consider adjusting the language of the standard to require more transparency and coordination with the UFLS entities during the PC's development of the UFLS program. Also, per the implementation plan, the PC will be given one year to develop its UFLS program. However, the timeframe for the UFLS entity is based on the schedule imposed by the PC. The implementation plan should allow the UFLS entity at least one year (maybe more per capital budget cycles) from the time the PC identifies the UFLS entity in their UFLS program. The UFLS entity will need sufficient lead time in those instances that require purchase of new UFLS equipment that will require long term budget planning for implementation. **Response: The SDT understands your concern and has added Requirement R14, which requires notification of UFLS entities of the UFLS program design and schedule for application and a requirement to respond to feedback received.** 2. The UFLS entities are identified in the UFLS program established by the PC. However, it is not clear where the PC is explicitly required to notify and coordinate with the UFLS entity. In Requirement R3 it is implied that the PC will notify and coordinate with the UFLS entity per the phrase "including a schedule for implementation by UFLS entities within its footprint". This requirement needs to be more explicit that the PC will notify the UFLS entity, and the measure for R3 needs to require proof that the PC has done this. **Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and**

Organization	Yes or No	Question 8 Comment
		response to feedback received.
SPP System Protection and Control Working Group	No	Why are Generator Owners not included in the Standard? The Planning Coordinator can't prove the design without the Generator Owner for Requirements R3 and R4.
Response: Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.		
Ameren	Yes	
American Transmission Co.	Yes	
Duke Energy	Yes	
Exelon	Yes	
Long Island Power Authority	Yes	
Manitoba Hydro	Yes	
MRO's NERC Standards Review Subcommittee (NSRS)	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC Planning Standards Subcommittee	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 8 Comment
United Illuminating Company	Yes	
Wisconsin Electric Power Company (dba We Energies)	Yes	
Indiana Municipal Power Agency	Yes	IMPA believes that this draft allows entities who are currently providing UFLS at the transmission level to stay in place and provide this service going forward. IMPA hopes that the Planning Coordinators will establish their UFLS program by using this current UFLS setup prvided by Transmission Owners and not force a financial burden onto Distribution Providers by requiring then to install UFLS equipment. In states such as Indiana and Illinois, UFLS is performed at the transmission level for some entities and includes all the distribution load in the area regardless of size and voltage connection to the BES.
Response: Thank you for your support.		
NERC Staff	Yes	NERC staff believes that the SDT has sufficiently identified the proper entities for UFLS coverage. NERC staff understands the comments raised by the industry regarding transfer of responsibilities, however, it is worth noting that some inconsistency has been created by the language used in the standard. It could be problematic that the entity with the original responsibility (the Distribution Provider) can delegate responsibility to another entity (the Transmission Owner), because even with that delegation, the Distribution Provider's original responsibility does not disappear.
Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.		
Illinois Municipal Electric Agency	Yes	Tbe SDT's consideration of comments during the second posting is very much appreciated. Applicability now reoognizes and preserves the widely used practice of a TO factoring interconnected DP (that does not own or operate UFLS equipment) load into the TO UFLS scheme.
Response: Thank you for your support.		
MEAG Power	Yes	This is an excellent language change.
Response: Thank you for your support.		
SERC SC UFLS Standard	Yes	We recommend that R3 be revised to require the PC to specifically notify the "UFLS Entities" in their PC area

Organization	Yes or No	Question 8 Comment
Drafting Team		that are part of the PC's UFLS program.
Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.		
Southern Company Transmission	Yes	We recommend that R3 be revised to require the PC to specifically notify the "UFLS Entities" in their PC area that are part of the PC's UFLS program.
Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.		
Progress Energy - Carolinas	Yes	We recommend that R3 be revised to specifically require the Planning Coordinator to notify the "UFLS entities" in their PC area that they are part of the PC's UFLS program.
Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.		

9. The SDT has modified the performance characteristics in Requirements R6.1 through R6.3 (now parts 3.1, 3.2 and 3.3 of Requirement R3) and the modeling requirements for generator underfrequency and overfrequency protection in Requirement R7.1 and R7.2 (now parts 4.1 through 4.6 of Requirement R4). The modifications replace the discrete points in these requirements with frequency-time curves that achieve the same reliability objective. The SDT agrees with several commenters in the second posting that this approach is easier to understand and better demonstrates the coordination the SDT has achieved with the requirements proposed by the Generator Verification SDT in proposed standard PRC-024. Do you agree with these changes?

Summary Consideration:

As a result of the comments received, the SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the Planning Coordinator to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.

Organization	Yes or No	Question 9 Comment
Xcel Energy		No comments
Long Island Power Authority	No	
Western Area Power Administration	No	
GDS Associates	No	- See the answer to question 10. pertaining the classification of generating units / plants
Response: See response to question 10		
MRO's NERC Standards Review Subcommittee (NSRS)	No	1. In R3, simply say that the "program shall shed at least 25% of island load" and avoid use of the formula. If the formula is retained, then we suggest that it be changed to the more common industry nomenclature of "imbalance = (load-generation)/generation."

Organization	Yes or No	Question 9 Comment
		2. In R4, we interpret that the Equivalent Inertia Analysis is a valid dynamic simulation methodology for certain aspects of UFLS assessments. This is a methodology that is often recommended in relay application guides and other technical references. Please clarify that this type of dynamic analysis would be accepted toward compliance with the "through dynamic simulation" portion of this requirement. For Attachment 1 (R4.1, R4.2 & R4.3) and Attachment 2 (R4.4, R4.5 & R4.6)3. Attachment 1 and 2 include transient frequency performance curves for at least 30%, 40% and 50% island imbalance. Otherwise, revise the titles for Attachments 1 and 2 to clearly qualify that the transient frequency performance curves apply for a 25% or less island imbalance and that programs which are larger than this minimum load shedding requirement do not have to meet this criteria when overloads are in excess of 25%. In addition, UFLS programs that are designed for appropriate performance under imbalance conditions above 25% will not have the same performance curves as programs that are designed for imbalance conditions of 25% or less. 4. If item #3 is not adopted, then the Under Frequency Performance Characteristic line in Attachment 1 should be extended from the knee at approximately 58.9 Hz (for 60 seconds) to 59.3 Hz or 59.5 Hz (for approximately 500 sec). The purpose is to define a single line of constant slope and to get rid of the arbitrary knee in the characteristic curve which serves no reliability purpose. The reason for this change is that the worst case frequency recovery time for frequencies between 58.7 Hz and 59.5 Hz may occur for imbalance conditions significantly less than 25% where the governor response prevents the load shedding blocks from picking up and where frequency recovery times are a function of governor response and system inertia. Likewise, it makes sense to extend this line below 58 Hz to at least as low a frequency as is covered by the generation protection curve. 5. Add a note to Attachment 1 that states, "Larger size UFLS programs (e.g., 40%) may require less restrictive (lower) underfrequency (as well as and/or longer time delays) due to island generation and protection characteristics. UFLS programs shedding more than 25% must also increase generation protection delay times and/or change set points to achieve coordination with load shedding. For example, Manitoba Hydro and Saskatchewan need to shed more than 30% of the area load to achieve reasonable frequency recovery in their islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable.Generator Underfrequency and Overfrequency Coordination Attachments 6. The Generation Owner off-nominal frequency coordination requirements and coordination curves should be included only in the PRC-006 standard and not the PRC-024 standard. The generator coordination curves relate directly to the PRC-006 assessment requirements and the PRC-006 curves will be duplicative of, and possibly contradictory to, the curves in the PRC-024 standard if they are finally approved and then changed in the future. 7. The generation coordination curves need to be appropriate for the different types of UFLS programs (e.g.

Organization	Yes or No	Question 9 Comment
		25%, 30%, 40%, 50%, etc.) that have, or will be, designed and implemented for different islands. Generation coordination curves for 25% UFLS programs will not be the same for other (e.g. 30%, 40%, 50%) UFLS programs. It can be demonstrated that as the size of the load shedding program is increased, the generation protection settings have to be modified accordingly to achieve the coordination objectives. UFLS programs that are designed for imbalances greater the 25% inherently require lower minimum frequencies and longer frequency recovery times 8. If item #7 above is not adopted, then revise the titles for generation coordination curves to clearly qualify that they apply for a 0% to 25% island imbalance and that programs which are larger than this minimum load shedding requirement do not have to meet this criteria when overloads are in excess of 25%. The generation protection line should extend to 57 Hz (at .3 sec) to 59.5Hz (at 1800 sec). The minimum frequency of 57.0 Hz was chosen because most conventional generation can briefly operate down to 57.0 Hz and large load shedding programs may need to make use of that capability to achieve coordination with these UFLS programs. 9. We are aware of the technical basis for the generator Under Frequency protection setting, but not aware of the technical basis for the presently proposed generation coordination curves in PRC-006 or PRC-024. We suggest that the SDT provide the industry with the technical basis for the generation coordination curves. We are concerned that the curves allow enough time for load shedding to operate under “worst case conditions”, and as much time as possible needs to be given for frequencies close to 60 Hz. We are also concerned that for actual UFLS events system frequency recovery may stall below 59.5 Hz for a long time while operators try to deal with event with manual shedding of load. Volts/Hertz Performance Characteristic 10. The Volts/hertz requirement is not needed in this standard and should be removed for several reasons: [1] Voltage regulators automatically reduce voltage according to volts per hertz when in the automatic mode so they self protect. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist that adequately address the volts/Hz issue. [2] If voltage regulators are in automatic, then the 110% volts/Hz limit becomes active between 57.2 Hz and 51.8 Hz assuming the voltage regulator holds terminal voltage within the allowed 1.05 p.u. to 0.95 pu range. [3] Units with voltage regulators in manual will just trip when volts per Hertz protection picks up. However, units are normally in the automatic control mode per NERC Standards. [4] It appears this requirement is appropriate for programs which may experience frequencies below 57.2 Hz, but few, if any, programs are expected to be designed for frequencies that are this low. [5] Even if UFLS programs are designed for frequencies below 57.2 Hz, this performance characteristic cannot presently be properly simulated in stability cases as the voltage regulator V/Hz controls are not

Organization	Yes or No	Question 9 Comment
		presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation
Response: The SDT is specifying a minimum requirement of a 25% imbalance to design the UFLS program to. Regional standards can be developed to define include larger imbalances. The formula provided in the standard adds clarity. Our interpretation is that Equivalent Intertia Analysis is not sufficient to meet all of the requirements of the standard. We have clarified the language of R4 and the knee of the curves in Attachment 1 to clarify that the UFLS program should be designed such that a steady state frequency between 59.3 and 60.7 Hz is reached within 60 seconds. The SDT believes there is a need for V/Hz requirements because shedding load will cause voltages to climb, which may cause excitation systems / voltage regulators to reach the end of their range, which can lead to a V/Hz condition that could cause generators to trip through GSU protection or other similar protection systems. Therefore, the SDT believes that V/Hz of 1.18 p.u for 2 seconds, etc., can be reached at significantly higher frequencies than 57.2 Hz. The standard does not require modeling of V/Hz protection and only requires monitoring of voltage and frequency and designing the UFLS program to meet the performance criteria described in 3.2. No changes made.		
American Transmission Co.	No	1. In R3, the term, “imbalance”, should be described using the standard industry nomenclature of imbalance = (load-generation)/generation. 2. In R4, we interpret that the Equivalent Inertia Analysis is a valid dynamic simulation methodology for certain aspects of UFLS assessments. So, we expect that this type of dynamic analysis would be accepted toward compliance with the “through dynamic simulation” portion of this requirement Attachement 1 for R4.1, R4.2, R4.33. The title for Attachment 1 should clearly qualify that this curve applies for a 25% or less island imbalance. The curves that should be used for UFLS programs associated with imbalance levels greater than 25% (e.g. 30%, 40%, 50%) would be different from the 25% curve. 4. The Under Frequency Performance Characteristic line in Attachment 1 should be extended to 59.5 Hz (at 500 sec). The reason for this change is that the worst case response between 58.7 Hz and 59.5 Hz may occur for imbalance conditions significantly less than 25% where the governor response prevents the load shedding blocks from picking up and where response recovery times is a function of governor response and system inertia (30 seconds to 500 seconds). This removes the knee of the curve at 30 seconds and extends the curve up to 500 seconds. This would change the 30 second at 58.9 Hz cut off point to 500 seconds. 5. Add a note to Attachment 1 that states, "Larger size UFLS programs (e.g., 40%) may require less restrictive (lower and/or longer time delays) underfrequeny limits due to island generation and protection characteristics." UFLS programs shedding more than 25% must increase generation protection delay times and/or change set points to achieve coordination with load shedding. For example, Manitoba Hydro and Saskatchewan need to shed more than 30% of the area load to achieve reasonable frequency recovery in their islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable.Attachment 2 for R4.4, R4.5, R4.66. The title for Attachment 2 should clearly qualify that this

Organization	Yes or No	Question 9 Comment
		curve applies for a 25% or less island imbalance. The curves that should be used for UFLS programs associated with imbalance levels greater than 25% (e.g. 30%, 40%, 50%) would be different from the 25% curve. Generator Underfrequency and Overfrequency Attachments 7. The Generation Owner off-nominal frequency coordination requirements and coordination curves should be included in the PRC-006 standard. The generation curves should be applicable for load shedding levels beyond the 25% (e.g. 30%, 40%, 50%). If curves beyond 25% are not include, then the titles of the curves should qualify that they apply for 25% imbalance and include an note regarding coordination with UFLS programs that shed higher than 25% of the island load. The line should extend to 57 Hz (at .3 sec) to 59.5Hz (at 1800 sec). The minimum frequency of 57.0 Hz was chosen because most conventional generation can briefly operate down to 57.0 Hz and large load shedding programs may need to make use of that capability to achieve coordination with these UFLS programs.Volts/Hertz Performance Characteristic 8. The Volts/Hz requirement should be removed. This performance characteristic cannot presently be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation. In addition, the Volts/hertz requirement is not need in this standard. Voltage regulators automatically reduce voltage according to volts per hertz when in the automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist that adequately address the volts/Hz issue.
Response: The SDT is specifying a minimum requirement of a 25% imbalance to design the UFLS program to. Regional standards or Variances can be developed to include larger imbalances. Our interpretation is that Equivalent Intertia Analysis is not sufficient to meet all of the requirements of the standard. We have clarified the language of R4 and the knee of the curves in Attachment 1 to clarify that the UFLS program should be designed such that a steady state frequency between 59.3 and 60.7 Hz is reached within 60 seconds. The SDT believes there is a need for V/Hz requirements because shedding load will cause voltages to climb, which may cause excitation systems / voltage regulators to reach the end of their range, which can lead to a V/Hz condition that could cause generators to trip through GSU protection or other similar protection systems. Therefore, the SDT believes that V/Hz of 1.18 p.u for 2 seconds, etc., can be reached at significantly higher frequencies than 57.2 Hz. The standard does not require modeling of V/Hz protection and only requires monitoring of voltage and frequency and designing the UFLS program to meet the performance criteria described in 3.2. No changes made.		
Manitoba Hydro	No	1. In R3, the term, “imbalance”, should be described using the standard industry nomenclature of imbalance = (load-generation)/generation. The present definition defines imbalance as being the same as the required percent load to be shed, and if this is what is intended, it would be better to keep it simple say that everyone needs to shed at least 25% load and avoid use of the term imbalance. In any event, the definition of “imbalance” should follow industry conventions for consistency. 2. For R4.1, R4.2, R4.3 - Attachment 1 and 2:2. The titles for Attachment 1 and 2 should clearly qualify that the transient frequency performance curve applies for a 25% or less island imbalance and that programs

Organization	Yes or No	Question 9 Comment
		which are larger than this minimum load shedding requirement do not have to meet this criteria when overloads are in excess of 25%. [If the SDT doesn't allow different characteristics for a higher than 25% program, then we propose that the MRO submit a variance for a 30% and higher UFLS programs.] We are quite concerned that the generation tripping curve part of attachments 1 and 2, which matches the curve in PRC-024, as it appears to that this applies to all overload levels and to any size of load shedding program. It can be easily demonstrated that as the size of the load shedding program is increased, that generation protection settings have to be modified accordingly. The reason is to achieve coordination objectives. When we are dealing with the larger imbalances we are also inherently dealing with lower minimum frequencies and longer frequency recovery times. To make matters worse, we are trying to approve PRC-006 using information from PRC-024 which is still a draft, not an approved standard.We would like to elaborate on problems related to the generation protection curve part of attachment 1: UFLS programs have to deal with several mutually conflicting objectives and by setting hard and fast limits for generation underfrequency protection up front, we are adding an unnecessary constraint which will have undesirable effects on other aspects of the program. Such generation protection settings have to be considered in the context of the overall set of compromises that go into UFLS program design. We have to consider what kind of frequency recovery can be achieved with a well coordinated load shedding program and we have to compare that performance to the true capabilities of the generation in the island. When all things are considered, a final compromise can be reached that gives the best of all worlds. The characteristic in PRC-024 is not representative of the raw data from the manufacturers that defines actual capabilities, instead it is just someone's estimation of what is a reasonable tradeoff, and represents some hypothetical amount of accelerated loss of life of the turbine. The generation protection curve from PRC-024 is at best a starting point. From a design perspective, we could use different and equally valid settings if needed. 3. 3. The Under Frequency Performance Characteristic line in Attachment 1 should be extended from the knee at approximately 58.9 Hz (for 60 seconds) to 59.3 Hz or 59.6 Hz (at for approximately 500 sec). The purpose is to define a single line of constant slope and to get rid of the arbitrary knee in the characteristic which serves no reliability purpose. The reason for this change is that the worst case frequency recovery time for frequencies between 58.7 Hz and 59.5 Hz may occur for imbalance conditions significantly less than 25% where the governor response prevents the load shedding blocks from picking up and where frequency recovery times is are a function of governor response and system inertia. Likewise it makes sense to extend this line below 58 Hz to at least as low of a frequency as is covered by the generation protection curve spicily for the hydro generator as of Manitoba Hydro case. 4. 4. Add a note to Attachment 1 that states, "Larger size UFLS programs (e.g., 60%) may require less restrictive (lower) underfrequency (as well as and/or longer time delays) due to island generation and protection characteristics. UFLS programs shedding more than 25% must also increase generation protection delay times and/or change set points to achieve coordination with load shedding. For example, Manitoba Hydro needs to shed more than 30% of the area load to achieve reasonable frequency recovery

Organization	Yes or No	Question 9 Comment
		in it island. In this case, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable.For R4.4, R4.5, R4.6 - Attachment 2: Generator Underfrequency and Overfrequency Attachments: 5. 5. The Generation Owner off-nominal frequency coordination requirements and coordination curves should be included in the PRC-006 standard and PRC-024 should be scrapped. How can PRC-006 even proceed with using curves from PRC-024 when PRC-024 is still being drafted and subject to change? We could approve PRC-006 only to find subsequent changes to PRC-024 have undermined everything. The generation curves which are used to set generation underfrequency protection need to be appropriate for the system studied and one size does not fit all. The generation protection curves in Attachments 1 and 2 appear to be someone's personal estimation of what is a reasonable amount of accelerated loss of life per event but the flaw is that this was developed without first finding out what is really needed to ensure a well coordinated UFLS plan that meets all of the other objectives (planning engineers need to be able to coordinate generation protection with load shedding frequency recovery times as part of the study process, as the recovery times are influenced by the design objectives of the UFLS program). This generation off-nominal frequency characteristic is not what manufacturers provide as limits on their machines. No technical justification was ever provided for these curves that were developed in PRC-024, and that justification is needed. It is insufficient to say that PRC-006 is justified in using this just because it came from PRC-024. The technical justification was never part of any NERC standards drafting effort. Limits of this nature should not be created arbitrarily, and have to be selected as part of the overall final compromise involved in UFLS design to ensure we give enough time for load shedding to operate under worst case conditions, and as much time as possible needs to be given for frequencies close to 60 Hz as UFLS events show that in the real world that things do not always work as planned and system frequency can stall out below 59.5 hz for a long time while operators try to deal with this by manually shedding load. If the generation protection curves are not appropriate for programs covering overloads beyond 25%, then the titles of the curves should qualify that they apply for a 0% to 25% imbalance and include an note that different settings may be needed to coordinate with UFLS programs that shed more than 25% of the island load. Volts/Hertz Performance Characteristic: 6. The Volts/hertz requirement is not need in this standard. There are a couple of reasons. Voltage regulators automatically reduce voltage according to volts per hertz when in the automatic mode so they self protect. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist that adequately address the volts/Hz issue. If voltage regulators are in automatic, the 110% volts/Hz limit kicks in between 57.2 Hz and 61.8 Hz assuming the voltage regulator holds terminal voltage within the allowed 1.05 pu to .95 pu range. Units with voltage regulators in manual will just trip when volts per Hertz protection picks up. Units are normally in automatic control so this is not a big worry. It appears this requirement is appropriate for programs which may experience frequencies below 57.2 Hz, but few programs will see frequencies this low. Of course that makes it very

Organization	Yes or No	Question 9 Comment
		easy to demonstrate that programs satisfy this requirement, but it still seems there is no need to put this in the standard.As such, we believe the Volts/Hz requirement is of questionable worth for programs covering overloads of up to 25%, and should be removed. Even if system frequency were to drop below 57.2 hz, this performance characteristic cannot presently be properly simulated in stability cases as the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation.
Response: The SDT is specifying a minimum requirement of a 25% imbalance to design the UFLS program to. Regional standards (or Variances) can be developed to include larger imbalances. Our interpretation is that Equivalent Intertia Analysis is not sufficient to meet all of the requirements of the standard. We have clarified the language of R4 and the knee of the curves in Attachment 1 to clarify that the UFLS program should be designed such that a steady state frequency between 59.3 and 60.7 Hz is reached within 60 seconds. The SDT believes there is a need for V/Hz requirements because shedding load will cause voltages to climb, which may cause excitation systems / voltage regulators to reach the end of their range, which can lead to a V/Hz condition that could cause generators to trip through GSU protection or other similar protection systems. Therefore, the SDT believes that V/Hz of 1.18 p.u for 2 seconds, etc., can be reached at significantly higher frequencies than 57.2 Hz. The standard does not require modeling of V/Hz protection and only requires monitoring of voltage and frequency and designing the UFLS program to meet the performance criteria described in 3.2. No changes made.		
ReliabilityFirst Engineering Staff	No	1. It is not clear how the PC is supposed to enforce performance characteristic 3.3. Part 3.3 is written based on general over-excitation limits for generators and transformers. However, entities should already have over-excitation protection on critical equipment. Isn't the owner obligated to protect its equipment? Also, V/Hz at a bus is not a standard output of dynamic stability programs making it difficult to ensure compliance to part 3.3. It would be more useful if part 3.3 was expressed in terms that are commonly available such as voltage. Additionally, the meaningful per unit voltage is the machine or equipment base and the results would need to be scaled from the system base voltages. 2. The reliance on curves in Attachments 1 and 2 is imprecise. The frequency and time coordinates of each change in slope should be given so that entities do not need to interpret it themselves.3. The standard relies too heavily on the possible implementation of proposed standard PRC-024.4. The proposed PRC-006-1 UFLS standard and companion PRC-024 establish tightly defined performance characteristics which at best will just barely work for 30% UFLS programs using 3 steps of 10% load shedding. More precisely, it works for a 30% UFLS program for a range of conditions, but not for all of the conditions that can exist or are expected to exist in various portions of ReliabilityFirst over the next five years. Thus, ReliabilityFirst staff believes that these performance characteristics coupled with declining governor response and declining equivalent inertia in the Eastern Interconnection, will encourage a redesign of one or both of the existing 30% UFLS programs within ReliabilityFirst.
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a		

Organization	Yes or No	Question 9 Comment
UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachement 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters. No changes made.		
Northeast Power Coordinating Council	No	Although the DT's decision to replace the discrete points in these requirements with frequency time curves that achieve the same objective, the applicability requirement in Requirement R3.3, which addresses Volts per Hz performance characteristics, lists each generator bus and generator step-up transformer high-side bus associated with generating facilities defined in sub-requirements 3.3.1, 3.3.2, and 3.3.3. The facilities listed in the above sub-requirements appear to be quoted from the NERC Statement of Compliance Registry Criteria, Sections III.c.1 & III.c.2. It is not clear why sub requirement 3.3.3 is necessary since it is simply a restatement of requirement 3.3.2. Suggest that 3.3.3 be eliminated and that 3.3.2 be re-written to be consistent with the Registry, Section III.c.2, "Generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating."
Response: The SDT believes Requirememnt R3, Parts 3.3.1 through 3.3.3 are consisent with the Statement of Compliance Registry.		
Bonneville Power Administration	No	Each interconnection should establish discrete set points based upon stability and dynamic analysis. Discrete set points can help establish criteria which are measurable and performance-based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC. The Standard needs to be very explicit that the curves are interconnection performance curves and not entity specific set points. What is the technical justification and correlation of the curves to the UFLS Plans, i.e. where did these curves come from?
Response: The SDT believes that the degree of diversity in systems of various regions, particularly in the Eastern Interconnection, makes the determination of UFLS program design parameters an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design. The under and over frquency performance curves are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points. The over and under frequency versus time performance curves for UFLS were determined to coordinate with the Generator under and over frequency tripping curves (which have been also coordinated with the PRC-024 SDT) and to set a margin between the UFLS and generator curves.		

Organization	Yes or No	Question 9 Comment
Tri-State Generation & Transmission Assoc.	No	Each interconnection should establish discrete set points based upon stability and dynamic analysis. From discrete set points one can establish criteria which are measurable and performance based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC. Furthermore, the Standard needs to be very explicit that the curves are interconnection performance curves and not specific protective relay set points.It is recommended to combine Attachment 1 and Attachment 2 (which contain discrete set points) into a single graph, making frequency the abscissa, and requiring simulations to maintain frequencies inside the resulting envelope.R3.3. While the concern for loss of additional generation units because of their V/Hz protection schemes is understood, the bases for the 1.18pu and 1.1pu values are not evident and may not be technically supportable when compared against actual protection settings or allowable post-contingency voltage bands. Further, V/Hz protection settings vary across the system and it is unlikely adherence to this requirement will impact reliability. It will only increase dynamic analysis requirements. We recommend removing R3.3.
Response: The SDT believes that the degree of diversity in systems of various regions, particularly in the Eastern Interconnection, makes the determination of UFL:S program design parameters an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design. The SDT intends to combine Attachments 1 and 2 into one Attachment. The under and over frquency performance curves are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points. Requirement R3, Part 3.3 is based on IEEE guidelines for setting V/Hz protection. The SDT has debated the question of Requirement R3, Part 3.3 and has decided to retain the V/Hz requirement. The SDT is aware that there have been instances in UFLS studies where V/Hz has been seen as a risk to the tripping of generation and does not wish to leave a possible gap in reliability.		
IESO	No	If the overfrequency characteristics are retained, it would be better to combine Attachment 1 and Attachment 2 into one curve. The curves without some explanation may not be consistently interpreted. Should the level line at the shortest times (e.g. < 2 s) and vertical line at the longest time (e.g. > 60s) for the Performance Characteristic be interpreted to mean UFLS tripping is permitted without delay below 58.0 Hz and is not permitted above 59.3 Hz?
Response: The SDT intends to combine Attachments 1 and 2 into one Attachment. The under and over frquency performance curves are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points.		
AECI	No	It is unclear what the system frequency should be after the blue line ends.
Response: The SDT fully expects that UFLS simulations will not need to be run beyond 60 seconds and that steady-state conditions between 59.3 and		

Organization	Yes or No	Question 9 Comment
60.7 Hz should be achived well before 60 seconds in most UFLS simulations.		
MidAmerican Energy	No	R3.3 should be deleted as it does not directly apply. If volts / hertz requirements remain, they should be consistent with the proper IEEE standards.
Response: The SDT has debated this question and has decided to retain the V/Hz requirement. The SDT is aware that there have been instances in UFLS studies where V/Hz has been seen as a risk to the tripping of generation and does not wish to leave a possible gap in reliability. Requirement R3, Part 3.3 is based on IEEE guidelines for setting V/Hz protection.		
Southern California Edison Company	No	SCE agrees with WECC's position that "This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided."
Response: The SDT believes that the degree of diversity in systems of various regions, particularly in the Eastern Interconnection, makes the determination of UFLS program design parameters an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design.		
Western Electricity Coordinating Council	No	The devices which implement UFLS must have discrete setpoints. The standards must establish criteria which is measurable. This type of criteria is only measurable by study or actual performance following a UFLS event. The planning criteria may use curves but these must be translated to a setpoint which can be verified.Each interconnection should establish discrete set points based upon stability and dynamic analysis. From discrete set points one can establish criteria which are measurable and performance based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC.The Standard needs to be very explicit that the curves are interconnection performance curves and not entity specific set points.What is the technical justification and correlation of the curves to the UFLS Plans, i.e. where did these curves come from?
Response: Each PC will need to devise UFLS Program design parameters that result in observance of the under and over frequency performance curves duing dynamic simulations of under frequency events and islands. The under and over frquency performance curves are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points.		

Organization	Yes or No	Question 9 Comment
The over and under frequency versus time performance curves for UFLS were determined to coordinate with the Generator under and over frequency tripping curves (which have been also coordinated with the PRC-024 SDT) and to set a margin between the UFLS and generator curves.		
South Carolina Electric and Gas	No	The graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curves data points.
Response: The SDT intends to document the data points for the curves.		
Exelon	No	The standard lacks guidance as to what the trip settings should be. It is not clear as to how Attachment 1 should be used and doesn't provide specific detail for under frequency set points. Exelon disagrees that R3.3 is easier to understand. Clarification is needed as to where the underfrequency set points are. Do all entities contribute equally to Attachment 1? There needs to be a standardized relationship between GO and TO/DP participation in obtaining the desired level of system performance. There should also be explicit criteria as to what the expectations are for each individual entity. It should be clear that all UFLS entities are to participate equally and that larger entities will not be expected to carry the burden for smaller entities.There should be some recognition in the standard that UFLS schemes currently exist and effort should be made to avoid needlessly changing relays or settings on many thousands of installations if some arbitrary and common set points were to be determined by the PC, thus causing needless expense. It is likely desireable to have slightly different settings for UFLS across a footprint so as to not create load changes that are too abrupt.The current practice of allowing contractual agreements between GOs and DPs for additional load shedding as a voluntary business decision, in the event that a unit owner doesn't comply with the unit trip settings should be addressed.
Response: The under and over frquency performance curves are solely for checking dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points. Requirement R3, Part 3.3 is based on IEEE guidelines for setting V/Hz protection. The Planning Coordinator, as part of the UFLS program design, will need to determine the participation level of the variously sized Transmission Owners and Distribution Providers. The SDT fully expects that existing UFLS programs will be sufficient to comply with the performance characterisitic curves and the the Planning Coordinators will not need to arbitrarily redetermine UFLS design parameters. The SDT has addressed the matter of GO versus TO/DP obligation for non-conforming generators and has decided that, for the likely small amount of non-conforming generation, that it should be a small burden, if any, to be spread across multiple TO sand DPs.		
FirstEnergy	No	We are concerned about the coordination between this UFLS SDT and the GV SDT. It will be difficult to approve and begin implementing the PRC-006-1 standard while the PRC-024-1 standard is still under development and scheduled for approval and implementation at a much later date. For these requirements to be adequately coordinated, the two standards need to be developed, balloted and implemented at the same

Organization	Yes or No	Question 9 Comment
		time. Alternatively, consider adding the following statement in the PRC-006-1 Implementation Plan: "The Effective Date and implementation of this PRC-006-1 standard requires coordination with standard PRC-024-1. Excluding requirement R1, the Effective Date of PRC-006 shall be the later of 1) the completion of the Implementation Plan for PRC-006 or 2) the completion of the Effective Date of the PRC-024-1 standard upon completion of its Implementation Plan."
Response: The UFLS (PRC-006) SDT has coordinated with the PRC-024 SDT. The SDT believes that even though the two standards are on different development schedules, there will not be miscoordination of the generator under and over frequency tripping curves, and the requirement on collection of data for the Planning Coordinators to obtain under and over frequency trip settings.		
Ameren	No	While this is an improvement over the previous draft, we still believe that Requirement R3.3, dealing with generator V/Hz limitations, should not be part of this standard.
Response: The SDT has debated this question and has decided to retain the V/Hz requirement. The SDT is aware that there have been instances in UFLS studies where V/Hz has been seen as a risk to the tripping of generation and does not wish to leave a possible gap in reliability.		
Duke Energy	Yes	
Entergy Services	Yes	
Indiana Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
MEAG Power	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
SERC Planning Standards Subcommittee	Yes	

Organization	Yes or No	Question 9 Comment
SERC SC UFLS Standard Drafting Team	Yes	
Southern Company Transmission	Yes	
SPP System Protection and Control Working Group	Yes	
Tennessee Valley Authority (TVA)	Yes	
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
Progress Energy - Carolinas	Yes	The curves added as Attachments 1 and 2 are excellent. However, it would be helpful if a footnote to the curves provided the values of the "transition points" or breakpoints of the curves. For example on Attachment 1, there appears to be transition point at 60 seconds/58.85 Hz, but it is difficult to read exactly.
Response: The SDT intends to document the data points for the curves.		
Wisconsin Electric Power Company (dba We Energies)	Yes	We agree with the concept of using the frequency time performance curves instead of discrete points. However, we would like the SDT to provide additional technical background on the methodology utilized to develop both the underfrequency and overfrequency time performance curves beyond what was discussed in the "Review of Technical Changes to Standard" section in the preface of the "Unofficial Comment Form."
Response: The over and under frequency versus time performance curves for UFLS were determined to coordinate with the Generator under and over frequency tripping curves (which have been also coordinated with the PRC-024 SDT) and to set a margin between the UFLS and generator curves. That is about all that can be said.		
NERC Staff	Yes	Yes, NERC staff supports the idea of better demonstrating coordination with the requirements proposed for PRC-024.
Response: Thank you for your comment.		

10. Besides replacing the discrete point thresholds in R7.1 and R7.2 (now parts 4.1 through 4.6 of Requirement R4) with curves, the SDT has clarified which generators with under- and underfrequency trip settings above and below these curves, respectively, must be included in the UFLS assessments in parts 4.1 through 4.6 of Requirement R4. The generators with non-conforming trip settings that must be included in the UFLS assessments are now limited to individual generating units greater than 20 MVA or generating plants/facilities greater than 75 MVA directly connected to the BES or any facility consisting of one or more units that are connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. This clarification also makes parts 4.1 through 4.6 consistent with the generator size and connection thresholds in part 3.3.1 of Requirement R3. Do you agree with this clarification?

Summary Consideration: In response to the comments received, The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of Attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria.

Organization	Yes or No	Question 10 Comment
Southern California Edison Company		SCE is unsure of the ramifications of this change and, therefore, cannot confirm that we are in agreement with the change.
Response: Thank you for your comment		
Long Island Power Authority	No	
GDS Associates	No	- Not sure what is the intent of this classification of generating units >20MVA, generating facilities (two or more units) directly connected to BES >75MVA and generating facilities connected to a common bus to BES >75MVA- Are the requirements for the two
Response: The intent is to match the Statement of Compliance Registry Critiria.		
AECI	No	AECI can understand how we should be responsible for our own data, but the data we use for others is only as good as the data we receive. It seems like this standard also needs to apply to generator owners

Organization	Yes or No	Question 10 Comment
Response: The implementation plan and effective date language were changed to clarify that modeling of generator trip settings that do not conform with the curves of new Attachment 1 will only be effective after the Planning Coordinator receives the appropriate data in accordance with Project 2007-09 Generator Verification for draft Standard PRC-024 currently in development.		
Tri-State Generation & Transmission Assoc.	No	Comments: Underfrequency is an issue of load and generation balance. It does not make sense to make the distinction of whether or not a generator or generating facilities directly connect to the BES. The loss of sizable generation has the same impact on frequency regardless of what voltage it was connected at. The thresholds used in the standards are registration thresholds for the GO/GOP function. There is nothing that would prohibit a PC, TO or TOP from establishing interconnection requirements for smaller generators that require compliance with an UFLS program if it was important to reliable BES operation
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		
Exelon	No	Exelon feels that a table should be included with the curves. What was the source of the curves and the V/Hz requirements? The table seems to indicate that it is acceptable for the Eastern Interconnection to remain at 58.9 Hz for up to one minute. The data requirements for the assessment study should include additional data other than that for units out of compliance, i.e. all loads for the entire system as load is dropping.
Response: Formulas are now provided to supplement the curves. Requirement R4 has been modified to clarify that a steady state condition between 59.3 and 60.7 Hz is expected within 60 seconds, which is the intent of the vertical lines in the curves of Attachment 1. The source of the curves is to provide a margin between the curves developed in Project 2007-09 Generator Verification for draft Standard PRC-024. The V/Hz requirements are derived from IEEE standards. To clarify, units not in comformance with the curves are not necessarily out of compliance. Load modeling is an integral part of the dynamics database developed through the MOD standards.		
ReliabilityFirst Engineering Staff	No	It is not clear how the PC will determine which generating units are non-conforming as there is no requirement for the GO to provide this information in this standard. In a best case, it relies on the adoption of proposed standard PRC-024.
Response: The implementation plan and effective date language was changed to clarify that modeling of generator trip settings that do not conform with the curves of new Attachment 1 will only be effective after the Planning Coordinator receives the appropriate data in accordance with the Project 2007-09 Generator Verification for draft Standard PRC-024 currently in development.		

Organization	Yes or No	Question 10 Comment
NERC Staff	No	NERC staff disagrees with limiting the level of modeling in the assessments and feels that the modeling of generation should go beyond the 20 MVA and 75 MVA units as proposed. NERC staff believes that the UFLS design assessment should not be limited to modeling BES-connected resources. During a frequency excursion, all generation and frequency responsive devices "see" the excursion and react to it, regardless of size and location. Further, as penetration increases for similarly influential blocks of non-traditional resources (i.e., wind and solar farms) that have common underfrequency trip performance characteristics, it is essential that these dynamics and underfrequency trip characteristics should also be modeled and taken into account. This is not to say that each individual wind turbine or 500 kW generator must be modeled everywhere. However, when aggregate groupings of smaller units are known to be influential in dynamics analysis, or groupings of non-traditional resources with like frequency performance characteristics exist, it is essential that their influence be analyzed regardless of their voltage connection. The contribution to frequency response or common-mode tripping of such resources could mean the difference between a successful and unsuccessful UFLS system design.
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		
FirstEnergy	No	See our concerns in Question 9 about the coordination between this UFLS SDT and the GV SDT.
Response: The implementation plan and effective date language were changed to clarify that modeling of generator trip settings that do not conform with the curves of new Attachment 1 will only be effective after the Planning Coordinator receives the appropriate data in accordance with Project 2007-09 Generator Verification for draft Standard PRC-024 currently in development.		
Northeast Power Coordinating Council	No	Similar to the comment provided in response to Question 9, requirements 4.3 and 4.6 are simply restatements of requirements 4.2 and 4.5, respectively. Suggest that requirements 4.3 and 4.6 be eliminated, and that requirements 4.2 and 4.5 be rewritten to contain the language dealing with the applicability of composite facilities as defined in the Registry Criteria Section II.c.2.Additionally, this draft version of PRC-006 states in requirements 4.1 through 4.6 (as well as in requirements 3.3.1 through 3.3.3) that the assessment of non-conforming generator trip settings is limited to those generators generally defined by the Registry Criteria, rather than assuming that the Functional Entities shown in the Applicability Section of the Standard are further defined by the NERC Registry Criteria. This limitation is not necessarily valid for situations where any generator, regardless of size, is material to the reliability of the BES (Registry Criteria III.c.4). In particular during the development of a supporting Regional Standard it is quite possible that the amount of generation

Organization	Yes or No	Question 10 Comment
		whose non-conforming performance characteristics may be tolerated, (and thus eliminated from assessment consideration), will be very limited. In regions where a great preponderance of the total generation is comprised of smaller units the tolerance threshold for ignoring generation below a bright line value defined by PRC-006 may invalidate conclusions of the Regional UFLS Program assessments. These conclusions presently demonstrate that the Regional Program meets the broad performance characteristics and/or requirements of PRC-006. The PRC-006 SDT should be aware that those RSDTs developing Regional Standards will, based on necessity, assess the applicability of Functional Entities and to the degree that a materiality issue is raised will bring that issue before the Regional Entity. Regional Entities would be expected to confirm that reliability is at stake prior to the issuance of a Compliance Guidance Statement, or other communication tool. The RSDT expects that the reach of applicability governing the registration and compliance obligations of any such Functional Entity identified under the “material to the reliability of the bulk power system” clause of the Registry Criteria will be clearly defined in each Regional Standard.Generation facilities which do not meet the NERC generator registration criteria could avoid obligations to meet generator underfrequency and overfrequency trip requirements presented in the standard. Significant amounts of generation categorized as such could cumulatively jeopardize the performance of a UFLS program.Possible future trends in the development of generation could increase the amount of installed generation capacity that does not meet the NERC generator registration criteria. Such trends may include the development of renewable distributed generation that is not connected to the BES system.
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard’s implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		
IESO	No	The SDT should clarify the characteristics define where the generators are not permitted to trip rather than define where generators must trip. Correspondingly, it should be clarified for loads, the requirement defines the outer perimeter where UFLS loads must be tripped rather than to define where UFLS loads trip.The phrase; “directly connected to the BES” could be problematic. In the IESO-controlled grid most generators are connected to transmission system with a main output transformer. At many large generating stations, the low voltage bus of these MOTs where the generator is directly connected is not part of the BES while the high voltage bus is part of the BES. A restrictive interpretation of the present wording of the standard would limit applicability to only generating units captured under Â§R3.3.3, What interpretation of “directly connected” was intended by the SDT?Elements of this continent-wide standard are viewed by the IESO as a means to improve reliability not as a justification to weaken existing good practices. Does the STD support retaining existing more stringent standards (e.g. lower underfrequency thresholds and higher overfrequency thresholds or both) for generating units at the Regional or Planning Coordinator level? For example, the IESO-controlled

Organization	Yes or No	Question 10 Comment
		grid mandate generating units > 10 MW and generating facilities > 50 MW directly connected to the IESO-controlled grid to have generator protection set at a level such that they do not trip over the NPCC criteria for generator underfrequency curve. We need to seek the SDTs view on whether these conditions are sufficient to satisfy the intent of the PRC-006 standard.The response of the SDT to the earlier question (see below) concerning the need for overfrequency settings as part of this standard was not satisfactory as new requirements should have a strong motivation. Our Area experienced frequency excursions above those proposed in this standard without material adverse effects. Generation trips at these frequency levels in 2003 would have been inconsistent with the purpose of providing last resort system preservation measures. What are these referenced withstand capabilities and are they applicable to all types of units? What evidence is known to the SDT that units experience a significant loss of life due to the events on August 14, 2003 now that more than six years has passed? Why does the SDT believe overfrequency thresholds are necessary to fulfill the Purpose of this standard?[Response: Thank you for your comments. The SDT has developed the overfrequency characteristic in Requirement R6.3 to coordinate with the overfrequency trip setting limits proposed in PRC-024. The trip setting limits were developed by the Generator Verification SDT based on the withstand capabilities of generating units. The concern with operation of generating units at off-nominal frequency is the cumulative fatigue effect, so it is possible that generating units experienced significant loss of life on August 14, 2003 even if the adverse effects were not readily observable immediately after this event.]
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachement 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. **The term "directly connected" is intended in the same fashion as it is used in the Statement of Compliance Registry Criteria.** **Regional standards can be more restrictive than the national standard.**		
Bonneville Power Administration	No	Underfrequency is an issue of load to generation balance regardless of the voltage of the interconnection.
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of Attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		
Western Electricity Coordinating	No	Underfrequency is an issue of load to generation balance. It does not seem to make sense to make the distinction of whether or not a generator or generating facilities directly connect to the BES. The loss of

Organization	Yes or No	Question 10 Comment
Council		100MW of generation has the same impact on frequency if they are connected at 69kv or 500kv. The thresholds used in the standards are registration thresholds for the GO/GOP function and do not negate the impact of all generation on frequency response.
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of Attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan. As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		
Wisconsin Electric Power Company (dba We Energies)	No	We agree with the concept of using the PRC-024 generator underfrequency and overfrequency tripping curves instead of discrete points. In addition, we agree with the generator size and connection threshold clarification. However, we continue to believe that this standard places a burden on the UFLS Entity to shed additional load to make up for generators which do not conform to the PRC-006/PRC-024 curves. For example, if an independent power producer did not conform with the PRC-006/PRC-024 curves, it places a burden on the UFLS Entity to potentially have to shed additional load, up to the generator's rating, to make up for the non-conforming independent generator.
Response: Generator conformance with Project 2007-09 Generator Verification for draft Standard PRC-024 is beyond the scope of this standard. The SDT simply wants to recognize that some generators may not conform with that the resulting PRC-024 standard. No change made.		
Xcel Energy	No	We feel that our comment in the previous draft was not fully addressed. The dynamic simulation would need to include any small generators (<20MVA or <75MVA aggregate) that are not required to register, but together, could have a material impact on the BES. Additionally, it would need to be clear who is responsible for ensuring those material impacts are included in models/simulations.Distributed Generation (DG) is a growing concern that can have an impact on UFLS programs. Consider the need for adding that the assumptions related to DG be included in the R3 & R4 requirementsAdditionally, the Statement of Compliance Registry lists additional criteria for generator registration (i.e. black start, determined to be material to BPS). Shouldn't these be captured, or a more simple approach may be that all registered GOs be required to provide the requested data?
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of Attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		

Organization	Yes or No	Question 10 Comment
Ameren	Yes	
American Transmission Co.	Yes	
Duke Energy	Yes	
Entergy Services	Yes	
IRC Standards Review Committee	Yes	
Manitoba Hydro	Yes	
MEAG Power	Yes	
MidAmerican Energy	Yes	
MRO's NERC Standards Review Subcommittee (NSRS)	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
SERC Planning Standards Subcommittee	Yes	
SERC SC UFLS Standard Drafting Team	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 10 Comment
Southern Company Transmission	Yes	
SPP System Protection and Control Working Group	Yes	
Tennessee Valley Authority (TVA)	Yes	
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
Progress Energy - Carolinas	Yes	We agree with respect to the Planning Coordinator simulation requirements for modeling as stated in R4. However, the UFLS standard has no requirement for the Generator Owners to provide this information. We have been told that this might be included in PRC-024 (currently under development). This should be a condition for approval of PRC-006. Additionally, the Generator Owners should be required to notify the PC of any Manual (i.e. operator actions) that would result in a trip above/below the specified generator curves of Attachments 1 and 2. It is recognized that manual operator actions would typically be later than the approximately 60 seconds or less simulation times that a PC would use. However, this information regarding manual trips would be necessary for appropriate planning.
Response: The implementation plan and effective date language was changed to clarify that modeling of generator trip settings that do not conform with the curves of new Attachment 1 will only be effective after the Planning Coordinator receives the appropriate data in accordance with the Project 2007-09 Generator Verification for standard PRC-024 currently in development.		
Indiana Municipal Power Agency	Yes	When looking at generation in the RFC region and by going with generating units that are specified in the current sub requirements of requirement 4, the Planning Coordinators will be capturing 96 PERCENT of the generation in the RFC region in their UFLS program and design assessment (data supplied by RFC). When looking at generation between 69kV and 100kV, only about 2 PERCENT increase is gained in this area by requiring these Generation Owners to report information (this is making the assumption that all these lower voltage units have UFLS relays). One has to question the value of this increase in requiring these generating units to report information when load is not being captured that accurately and the modeling has a certain percent error.In addition, NERC reporting requirements will have to apply to these generating units connected between 69kV and 100 kV which will force the NERC registration of these units. NERC compliance has made

Organization	Yes or No	Question 10 Comment
		the statement on several documented occasions that if a new Generator Owner goes on the NERC registry, then that entity will have to meet ALL the NERC Generator Owner standard requirements in a NERC and FERC audit, NOT just the NERC UFLS standard. This would be a case where a standard drives the NERC Registry and IMPA does not believe that reliability standards should drive and change the NERC Registry.
Response: Thank you for your comments.		

11. The SDT has replaced Requirement R4 appearing in the previous (second) draft of the standard. Requirement R4 required each group of Planning Coordinators to develop a procedure for coordinating with groups of Planning Coordinators in neighboring regions within an interconnection to identify and reach agreement on islands between its region and neighboring regions within the interconnection. Requirement R4 was removed because procedures for coordination do not directly support reliability. In version 3 of the draft standard, any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating this selection with neighboring regions (Requirement R1). The SDT has added a requirement for the Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by any one Planning Coordinator that encompasses more than one Planning Coordinator footprint (Requirement R5). Do you agree with this revision?

Summary Consideration: Many commenters expressed concern that Planning Coordinators cannot be expected to reach concurrence with another functional entity because it is outside their control to lead them to concurrence. The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on UFLS design assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. The ERO could be the final authority if it wishes to assume that role, otherwise there would be no final authority.

Organization	Yes or No	Question 11 Comment
FirstEnergy		We defer an opinion on this and leave it to the Planning Coordinators to decide if this requirement is feasible for them to implement.
GDS Associates	No	- Requirement R1 is quite unclear. Not sure how the criteria will be developed especially to include the interconnected adjacent sections of the BES. What if one of the adjacent entities does not agree to the criteria? Is that OK because the Planning Coordinator will no longer join groups so is no need to coordinate? **Response: The SDT believes that criteria for determination of islands should consider past events and system studies. The criteria may be as simple or complex as a Planning Coordinator desires. Since these criteria are used only to identify islands for UFLS assessments, adjacent entities do not need to agree.**
Tri-State Generation &	No	Comments: Elimination of Requirement R4 is acceptable; however, we believe that individual Planning Coordinators are not the entities to determine how islands should be formed. The current registration by

Organization	Yes or No	Question 11 Comment
Transmission Assoc.		numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. R2.3 seems to require each Planning Coordinator to ultimately divide into multiple islands or separate its transmission system from all other transmission systems as its own island. Part of the purpose of the UFLS program should be to mitigate the need to form islands by balancing total system loads and resources. It is an additional function to balance the loads and resources after the islands have been formed. We recommend eliminating R2.
Response: The SDT shares the concerns about Planning Coordinator registration. However, there are no other entities in the Functional Model that would be any better for this role. The problem is a registration issue and it is possible that some registered Planning Coordinators do not fit the Functional Model description very well. **Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. Those islands are to be used only in UFLS design assessments, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The intent of R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. There are no requirements to identify Planning Coordinator footprints as islands.** **UFLS cannot be expected to mitigate island formation. Most interconnections are large enough that a decline in frequency low enough to cause UFLS operations is highly unlikely unless the interconnection is broken into islands. Most UFLS operations are seen to occur following island formation. The SDT does not agree that balancing load and generation after island formation is an "additional" function of UFLS.** **R2 cannot be eliminated because islands must be identified in order to carry out the UFLS design assessments (R4).**		
Exelon	No	Exelons concern is that neighboring Planning Coordinators will be making requests and setting criteria for the local planning coordinators and associated UFLS entities. We do not agree with the text "any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating."
Response: Identification of islands (R2) is for UFLS design assessments only (R4), a requirement that applies only to Planning Coordinators. UFLS entities are not affected, nor will a Planning Coordinator need to make requests of them or set criteria for them as far as island identification is concerned. The SDT believes the quoted text is necessary due to the wide range of island determination criteria (R1) that may be forthcoming.		
Western Electricity Coordinating Council	No	From an enforcement standpoint there is concern that if Planning Coordinator may choose its islands, what then is the process for getting "Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by any one Planning Coordinator". Who is the final authority and how is the arrangement memorialized and notified?Also, please see comment to Question #8 concerning the role of the RA.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still		

Organization	Yes or No	Question 11 Comment
believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on UFLS design assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. The ERO could be the final authority if it wishes to assume that role, otherwise there would be no final authority.		
Bonneville Power Administration	No	If each Planning Coordinator may choose its islands, what then is the process for getting "Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by any one Planning Coordinator". Who is the final authority and how is the arrangement memorialized and notified? No clear definition of a Planning Coordinator footprint may impact adequate identification of and authority related to establishing concurrence.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on UFLS design assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. The ERO could be the final authority if it wishes to assume that role, otherwise there would be no final authority. No requirement exists to identify Planning Coordinator footprints as islands.		
MidAmerican Energy	No	Instead of reaching concurrence, entities should be just required to inform adjacent interconnected NERC entities of the assessment results. Otherwise entities could potentially be held responsible for inaction of another planning coordinator. The language could be changed to be consistent with the language in EOP-003 R3, such as, "Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected (entities)".
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on UFLS design assessments. EOP-003, Requirement R3 is problematic in that there is no clear definition of "coordinate."		
Pepco Holdings, Inc. - Affiliates	No	It is difficult to see how this change corrected the described problem.
Response: It is a matter of ensuring that each requirement is linked to a reliability goal. The SDT believes that the change will be more acceptable to NERC and FERC approvers who are conscious of the need for each requirement to have a clear contribution to reliability.		
Tennessee Valley Authority (TVA)	No	R5 (and M5) is problematic in that it requires all affected PCs to reach concurrence. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard should require that one PC change its methods because another PC(s) does not agree with its methods, or agree that another method is acceptable that it finds a problem with. There needs to be a process in the event that PCs cannot reach concurrence. We recommend

Organization	Yes or No	Question 11 Comment
		that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island."
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others.		
American Transmission Co.	No	Replace the words "reach concurrence with" with "provide UFLS design assessment results to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion.		
Manitoba Hydro	No	Replace the words "reach concurrence with" with "provide UFLS design assessment results to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	Replace the words "reach concurrence with" with "provide UFLS design assessment results to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors.

Organization	Yes or No	Question 11 Comment
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion.		
Entergy Services	No	See above comment to questions #2 and #4.
SERC SC UFLS Standard Drafting Team	No	see above comment to questions #2 and #4.
Southern Company Transmission	No	see above comment to questions #2 and #4.
Progress Energy - Carolinas	No	See above comments to Questions #2 and #4.
Duke Energy	No	See comments above on questions #2 and #4.
IESO	No	The requirement to reach concurrence is outside of the capability of any single Planning Coordinator as concurrence requires at least two Planning Coordinators. The SDT should consider reformulating this requirement in terms of the actions it believes each Planning Coordinator must perform to reach concurrence with its fellow Planning Coordinators.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern.		
IRC Standards Review Committee	No	We agree with the need for Planning Coordinators in neighboring regions "to identify and reach agreement on islands between its region and neighboring regions". However, we believe new problems have been introduced. First, 2.3 under R2 is arbitrary and lacks any technical basis. There is no reason for splitting a island based on regional boundaries. Additionally, we are concerned that R1 may be viewed as an attempt to predict islands that may occur. Will a PC be held non-compliant if they predict incorrectly. There requirement needs to be clear that it is intended solely for the purpose of designing UFLS "islands".
Response: The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. Those islands are to be used in UFLS design assessments only, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. (The SDT agrees that there is no technical reason for designating Regional Entity footprints as islands.) **R1 does not require Planning Coordinators to predict islands that may occur in the future; it only requires criteria for island identification in order for the design assessments in R4 to be conducted. A Planning Coordinator cannot be judged non-compliant for failing to predict the future, but an**		

Organization	Yes or No	Question 11 Comment
unpredicted islanding event may be a reason to revisit the criteria.		
AECI	No	What if somebody else, with more stringent criteria than us, identifies us as an island and wants us to then conform to their more stringent criteria? It seems like if we did not identify them, the burden should not be placed on us. Also there seems to be potential for the actions of another utility to determine our compliance. **Response: The criteria required in R1 are for island identification only and are only to be applied by the Planning Coordinator that came up with them. No other Planning Coordinator is required to use or comply with another's R1 criteria. However, when the R4 assessment is performed, the other Planning Coordinator(s) in an island that spans two or more Planning Coordinator footprints will need to work with each other on the design assessments (R5) for those islands. (Note: R5 and R13 have been modified to address other commenter's concerns with the term "concurrence.")**
Ameren	Yes	
Indiana Municipal Power Agency	Yes	
Long Island Power Authority	Yes	
MEAG Power	Yes	
NERC Staff	Yes	
Northeast Power Coordinating Council	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC Planning Standards Subcommittee	Yes	

Organization	Yes or No	Question 11 Comment
South Carolina Electric and Gas	Yes	
SPP System Protection and Control Working Group	Yes	
Y-W Electric Association, Inc.	Yes	
Wisconsin Electric Power Company (dba We Energies)	Yes	Although we agree with the revision, we disagree with carrying forward the legacy concept of using an entire Regional Entity's footprint as an island. It is highly unlikely that the entire Regional Entity footprint would become an island. What is the technical justification for the continuation of the legacy concept of studying islands consisting of the entire Regional Entity's footprint? In addition, similar to the concurrence that the Planning Coordinators need to reach in R5, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: "The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets." Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R5, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: "The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission." Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly.
Response: The Regional Entity footprint islands are to be used in UFLS design assessments only, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. (The SDT agrees that there is no technical reason for designating Regional Entity footprints as islands.)		

Organization	Yes or No	Question 11 Comment
Several other commenters have expressed concern with use of the term "concurrence" and the SDT has modified R5 and R13 to address those concerns by removing "concurrence." The SDT agrees that UFLS Entities should have opportunity to provide input to the Planning Coordinator on what will be required of them. R14 has now been added to the standard and requires a peer review of a Planning Coordinator's design and schedule for implementation by the UFLS Entities. Hopefully, this addresses, at least in part, the commenter's suggestions.		
Xcel Energy	Yes	As long as the requirement as written still permits PCs to coordinate and select one or more islands between them to consider we are ok. Please clarify that R1 does not require that each PC must come up with their own unique island to consider.
Response: R1 only requires island identification criteria, not island identification, which is R2. Also, there are no requirements to identify Planning Coordinator footprints as islands. The only required islands are those portions of a system designed to island (Requirement R2, Part 2.2) and the Regional Entity footprint or interconnection islands (Requirement R2, Part 2.3).		
United Illuminating Company	Yes	Replace "reach" with "obtain".
Response: The SDT believes either term adequately conveys the intent and declines to make the change.		

12. The SDT added a Requirement R10 that requires each Transmission Owner to provide automatic switching of Elements in accordance with the UFLS program design. The SDT added this requirement in response to comments submitted in the second posting of the standard that indicated that automatic switching of Elements may be important as part of the UFLS program design. Do you agree with this requirement?

Summary Consideration:

Many commenters expressed concern that "switching of Elements" is not clear. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this 'providing' these elements is a function that would be performed by Transmission Owners.

Organization	Yes or No	Question 12 Comment
Western Electricity Coordinating Council		Requirement R10 is unclear and needs to be rewritten to assure the applicability.
Response: The SDT added this additional distinction for the purposes stated in Requirement R10. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Wisconsin Electric Power Company (dba We Energies)	No	Although we agree with the intent of this requirement, similar to the concurrence that the Planning Coordinators need to reach in R5 & R13, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: "The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission." Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R5 & R13, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: "The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic

Organization	Yes or No	Question 12 Comment
		tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets." Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly.
Response: The SDT understands your concern and has added Requirement R14, which requires notification of UFLS entities of the UFLS program design and schedule for application and a requirement to respond to feedback received.		
Tri-State Generation & Transmission Assoc.	No	Comments: Since "UFLS entity" already includes Transmission Owners, requirement R10 is unnecessary and "automatic switching of Elements" ought to be combined into R9 from R10 and then R10 can be deleted. **Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** UFLS programs should be developed by the Reliability Assurer, not individual Planning Coordinators. **Response: Our current understanding of the standards development process is that requirements written which apply to Reliability Assurer/Regional Reliability Organizations cannot be enforced the same way as other requirements. This standard is under development as a direct result of this particular issue and was identified as a part of a set of standards for having "fill in the blank" requirements. The SDT has crafted Requirements R5 and R13 in order to allow for and encourage coordination among PCs. This standard does not preclude the RRO/RA from performing this coordination function, but does not include a requirement for the RRO/RA for this purpose.**
American Transmission Co.	No	Consideration should be given to replacing "Transmission Owner" with "UFLS Entity" because the automatic switching of distribution Elements (e.g. capacitor banks) may be more effective and practical UFLS design than restricting the scope of the requirement to just transmission Elements.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
FirstEnergy	No	FE questions the need for this requirement and the Applicability Section item 4.3. FE asks that the SDT provide some examples of the reliability need related to frequency control for this requirement. If high voltage and automatic capacitor bank switching is the issue we don't believe that rises to a need as a reliability requirement within a UFLS standard. Voltage control should remain a separate issue from controlling frequency that this standard aims to address. Load shedding associated with UFLS is just one of many reasons why proper voltage control - through automatic Element switching of a capacitor bank - would be

Organization	Yes or No	Question 12 Comment
		needed for the transmission system. If there are other technical reasons for this requirement please clarify.
Response: Some members of the UFLS SDT have experience with these types of component switching which are integral to certain UFLS schemes where sudden loss of load can quickly negate the necessity of these reactive compensation devices and, in some instances, transmission lines. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Tennessee Valley Authority (TVA)	No	It is not clear what is included in automatic switching. If it is the automatic switching of Elements for the sake of removing load, it would appear to be covered under R9. **Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** R10 refers to "Elements" and M10 refers to "Facilities".In both R9 and R10, suggest replacing the word "provide" with "implement". **Respones: The SDT agrees and has edited R10 and M10 to amend this discrepancy.**
SERC Planning Standards Subcommittee	No	It is not clear what is included in automatic switching. This requirement is so vague that it does not appear to add anything in addition to the UFLS program design that it is intended to address. It appears that anything that R10 may be designed to address is already covered by R9.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Ameren	No	It is not clear what should be included in automatic switching. This requirement is vague. It appears that Requirement R9 would address anything that Requirement R10 would have been intended to cover.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Northeast Power Coordinating Council	No	Limiting applicability to only the TO limits the thrust of this requirement in cases where other FM entities are responsible for switching of elements that support the UFLS program. The Drafting Team should consider modifying R4 to include a requirement to model any automatically switched elements related to a UFLS program.The Drafting Team should consider a requirement to inform the Planning Coordinator of the implementation of UFLS relay inhibit schemes (e.g. voltage inhibit) and any associated parameters.

Organization	Yes or No	Question 12 Comment
		Knowledge of such information would be vital to the Planning Coordinator when assessing the performance of a UFLS program.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Bonneville Power Administration	No	Requirement R10 is unclear and needs to be rewritten to clearly address the applicability.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Southern California Edison Company	No	SCE would hope that the drafting team provides additional clarification on this requirement, as we are unsure of what the team intends by "automatic switching of Elements".
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	The NSRS basically agrees with the concept that owners of automatic switching elements provide control in accordance with the UFLS program requirements. Therefore, [1] consideration should be given to replacing "Transmission Owner" with "UFLS entity" because the automatic switching of distribution Elements (e.g. capacitor banks) may be more effective and practical in UFLS program design than restricting the scope of the requirement to just transmission Elements.[2] And consider replacing "UFLS program" with "UFLS program requirements".
Response: The SDT added this additional distinction for the purposes stated in Requirement R10. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
IESO	No	The STD may wish to consider reworking R10 in a format that matches changes to applicability. Within the IESO footprint, low voltage capacitors may be switched as part of the ULFS program. In some cases, these capacitors would below to Distribution Providers rather than Transmission Owners. "Each UFLS entity shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint."
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to		

Organization	Yes or No	Question 12 Comment
control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Xcel Energy	No	We have concerns that R9 & R10 provide the Authority of a PC to direct investment and actions to another entity, without the agreement from that entity. Thus we feel that R5 should be modified to require concurrence from each affected UFLS Entity as well.
Response: The SDT understands your concern and has added Requirement R14, which requires notification of UFLS entities of the UFLS program design and schedule for application and a requirement to respond to feedback received.		
Duke Energy	No	We question whether/how this requirement would apply to a Transmission Owner who has UFLS on distribution circuits. It's unclear to us how this would be determined by the Planning Coordinator.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
MEAG Power	No	What are automatic switching of elements? Does it mean that the TO needs to switch capacitor banks, or does it refer to the breakers equipped with UF relays? If it is referring to capacitor banks, is this applicable near major generation busses?
Response: The SDT has clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Y-W Electric Association, Inc.	No	Y-WEA is concerned about this requirement in that it seems to require the installation of facilities rather than just relays. 16 USC 824o (a)(3) gives NERC the authority to regulate existing facilities and planned additions or modifications to those facilities, not to prompt or require modifications or additions to the existing facilities. This proposed requirement seems to run afoul of this section of the USC.
Response: The SDT has added Requirement R14, which requires notification of UFLS entities of the UFLS program design and schedule for application and a requirement to respond to feedback received. **The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.**		
AECI	Yes	

Organization	Yes or No	Question 12 Comment
Exelon	Yes	
Illinois Municipal Electric Agency	Yes	
Indiana Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
Long Island Power Authority	Yes	
Manitoba Hydro	Yes	
MidAmerican Energy	Yes	
NERC Staff	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
ReliabilityFirst Engineering Staff	Yes	
South Carolina Electric and Gas	Yes	
SPP System Protection and	Yes	

Organization	Yes or No	Question 12 Comment
Control Working Group		
United Illuminating Company	Yes	
Entergy Services	Yes	It is not clear what is included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching of a capacitor to avoid overvoltage). **Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** R10 refers to "Elements" and M10 refers to "Facilities.", please change one of the references for consistency.In both R9 and R10, replace the word "provide" with "implement." **Respond: The SDT agrees and has edited R10 and M10 to amend this discrepancy.**
SERC SC UFLS Standard Drafting Team	Yes	It is not clear what is included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching of a capacitor to avoid overvoltage). **Respond: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** R10 refers to "Elements" and M10 refers to "Facilities."In both R9 and R10, replace the word "provide" with "implement." **Respond: The SDT agrees and has edited R10 and M10 to amend this discrepancy.**
Southern Company Transmission	Yes	It is not clear what is included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching of a capacitor to avoid overvoltage). **Respond: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** R10 refers to "Elements" and M10 refers to "Facilities."In both R9 and R10, replace the word "provide" with "implement." **Respond: The SDT agrees and has edited R10 and M10 to amend this discrepancy.**

Organization	Yes or No	Question 12 Comment
Progress Energy - Carolinas	Yes	It is not clear what would be included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching out of a capacitor bank to avoid overvoltage when designed as part of the UFLS scheme). **Respond: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** R10 refers to "Elements" and M10 refers to "Facilities". Revise to make consistent.In both R9 and R10, replace the word "provide" with "implement." **Respond: The SDT agrees and has edited R10 and M10 to amend this discrepancy.**

13. The SDT added new Requirements, R11 through R13. Requirement R11 requires each Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, to conduct and document an assessment of the performance of UFLS equipment and the UFLS program effectiveness within one year of event actuation. Requirement R12 requires Planning Coordinators, in whose islanding event assessments (per R11) UFLS program deficiencies are identified, to conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. Lastly, Requirement R13 requires Planning Coordinators, in whose footprint a BES islanding event affecting multiple Planning Coordinator footprints and resulting in system frequency excursions below the initializing set points of the UFLS program, to reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment is complete. These requirements were added to provide continuity on the requirement to assess UFLS program effectiveness for events since there is a similar requirement (with different applicable entities) currently in PRC-009-0, but PRC-009-0 is to be retired on approval of this standard. Do you agree with the addition of these requirements?

Summary Consideration:

Several commenters indicated that the requirement for the event assessment should contain a lower threshold. However, PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.

Several comments questioned whether the Planning Coordinator is the appropriate entity for UFLS activities. The SDT believes the Planning Coordinator, having a wide-area view and the necessary technical skills, is the proper entity to oversee the design and implementation of UFLS. There is also wide industry support for the Planning Coordinator as the proper entity for UFLS. The Reliability Assurer has a very limited scope of activity in the Functional Model and is not a user, owner or operator of the BES.

Organization	Yes or No	Question 13 Comment
Western Electricity Coordinating Council		From and enforcement standpoint whom is the final authority and how are arrangements memorialized and notified? In addition these requirements address issues which indicate a failure or inadequacy of the initial required planning process and appear overall to allow PC to establish a program based on inadequate study and then fix it after an event which proves the program was inadequate. All without any violation of standard.
Response: (Note: R5 and R13 have been modified to address other commenter's concerns with the term "concurrence.") For R13, the ERO could be the final authority if it wishes to assume that role, otherwise there would be no final authority.		

Organization	Yes or No	Question 13 Comment
Whether a UFLS plan or design is able to secure or would fail to secure a system or island during an underfrequency event is something that cannot be predicted ahead of time. This in no way suggests that the design and assessment requirements (R3 and R4) are somehow inadequate. 100 percent reliability cannot realistically be assured; it is possible that an underfrequency event may occur that exceeds the UFLS design parameters, but that is an acceptable risk. R12 is included so that, should an event occur where a UFLS design failed to secure a system or was otherwise deficient, a process to at least consider improvements or enhancements would be followed.		
FirstEnergy		We defer an opinion on this and leave it to the Planning Coordinators to decide if this requirement is feasible for them to implement.
GDS Associates	No	- Requirement R11. The one year deadline it seem very long. There can be multiple events before assessment is due. - Requirement R12. Same comment regarding the assessment due date. **Response: Some events can be very complicated and take much time to figure out. The SDT would rather allow too much time, rather than not enough time.**
American Transmission Co.	No	1. For R11, replace “Each Planning Coordinator, in whose footprint . . . to evaluate” with “When a disturbance event occurs in a Planning Coordinator’s footprint that involves automatic UFLS program operation or frequency excursions should have activated UFLS program operation, and a final disturbance report is required per EOP-004, each Planning Coordinator shall evaluate within one year of the disturbance event:”. 2. Either part of or after R11, there should be a requirement that “Each Planning Coordinator shall provide a preliminary event assessment report to the other Planning Coordinators who must conduct an assessment of the event for review at least 90 days before finalizing the event assessment report.3. For R13, replace “in whose footprint . . .on the event assessment result” with “that conducts an UFLS design assessment (per R12) for islands where other Planning Coordinators have design assessment responsibilities shall provide a preliminary design assessment report to those Planning Coordinators for review at least 90 days before finalizing the design assessment report. The reference to the event assessment report should be part of R11. The qualification of “event affecting multiple Planning Coordinators” is too vague and could be interpreted and categorized differently by various entities and auditors
Response: 1. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. **2, 3. These suggestions are more administrative to facilitate agreement. Requirements should try to spell out the reliability objective to be achived and less how a reliability objective may be achieved.**		
Manitoba Hydro	No	1. For R11, replace “Each Planning Coordinator, in whose footprint . . . to evaluate” with “When a disturbance event occurs in a Planning Coordinator’s footprint that involves automatic UFLS program operation or frequency excursions should have activated UFLS program operation, and a final disturbance report is

Organization	Yes or No	Question 13 Comment
		required per EOP-004, each Planning Coordinator shall evaluate within one year of the disturbance event:". 2. We have concerns about specifying that the evaluation must be complete within one year we know that some historical studies of events that included UFLS took longer than one year [e.g., three years] to complete. Therefore, we would prefer a more flexible wording, a longer time frame to be used in this requirement. Perhaps the requirement could stipulate that the evaluation must begin within 6 months and be completed within the schedule set by the investigative team. 3. For R13, replace "in whose footprint . . .on the event assessment result" with "that conducts an UFLS design assessment (per R12) for islands where other Planning Coordinators have design assessment responsibilities shall provide a design assessment report to those Planning Coordinators." The reference to the event assessment report should be part of R11. The qualification of "event affecting multiple Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors.
Response: 1. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. **2. One year ahould be sufficient for the majority of events.** **3. This suggestion is more administrative to facilitate agreement. Requirements should try to spell out the reliability objective to be achived and less how a reliability objective may be achieved.**		
MRO's NERC Standards Review Subcommittee (NSRS)	No	1. For R11, replace "Each Planning Coordinator, in whose footprint . . . to evaluate" with "When a disturbance event occurs in a Planning Coordinator's footprint that involves automatic UFLS program operation or frequency excursions that should have activated UFLS program operation, and a final disturbance report is required per EOP-004, each Planning Coordinator shall evaluate within one year of the disturbance event:".2. We have concerns about specifying that the evaluation must be complete within one year we know that some historical studies of events that included UFLS took longer than one year [e.g., three years] to complete. Therefore, we would prefer a more flexible wording, a longer time frame to be used in this requirement. Perhaps the requirement could stipulate that the evaluation must begin within 6 months and be completed within the schedule set by the investigative team. 3. For R13, replace "in whose footprint . . .on the event assessment result" with "that conducts an UFLS design assessment (per R12) for islands where other Planning Coordinators have design assessment responsibilities shall provide a design assessment report to those Planning Coordinators." The reference to the event assessment report should be part of R11. The qualification of "event affecting multiple Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors. 4. R11.2, change the wording to replace "effectiveness of the UFLS program" with "conformance with UFLS program design". Because no UFLS program can be designed to be effective for all possible contingency scenarios but should be effective for the contingency

Organization	Yes or No	Question 13 Comment
		scenarios for which it was designed.
Response: 1. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. **2, 3. These suggestions are more administrative to facilitate agreement. Requirements should try to spell out the reliability objective to be achived and less "how" a reliability objective may be achieved.** **4. The SDT disagrees because this change reduces the scope of the assessment. Conformance with UFLS program design is a subpart of effectivenss of UFLS program. The overal effectiveness is still of interest even if an event is beyond design capability.**		
Wisconsin Electric Power Company (dba We Energies)	No	Although we agree with the intent of these requirements, the assessment required in R11 & R13 should only be completed for significant UFLS events. Similarly, the significant event concept should be applied to the islanding criteria in R1. In fact, the SDT mentions this concept in the "Review of Technical Changes to Standard" section in the preface of the "Unofficial Comment Form." In the aforementioned section, the SDT uses a 500 MW qualifier which states "...resulting in 500 MW or greater of..." for R11 & R13 but the qualifier was not added to version 3 of the draft standard. Instead of an arbitrary 500 MW qualifier, the SDT should define islands of significance by looking at the transmission interface that feeds the potential island area and what is the IROL (Interconnection Reliability Operating Limit) for that transmission interface. If the amount of load in the island area is below the IROL limit, the island would not be considered as a basis in the UFLS program design and excluded from a UFLS assessment following a UFLS event. This significant event concept based on IROL should be included in the islanding criteria in R1 and the assessment requirements of R11 and R13. Similar to the concurrence that the Planning Coordinators need to reach in R13, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: "The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets." Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R13, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of

Organization	Yes or No	Question 13 Comment
		Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: "The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission." Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly.
Response: The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. **The Regional Entity footprint islands are to be used in UFLS design assessments only, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. The intent of R2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. (The SDT agrees that there is no technical reason for designating Regional Entity footprints as islands.)** **Several other commenters have expressed concern with use of the term "concurrence" and the SDT has modified R5 and R13 to address those concerns by removing "concurrence." The SDT agrees that UFLS Entities should have opportunity to provide input to the Planning Coordinator on what will be required of them. R14 has now been added to the standard and requires a peer review of a Planning Coordinator's design and schedule for implementation by the UFLS Entities. Hopefully, this addresses, at least in part, the commenter's suggestions.**		
Entergy Services	No	As noted in our response to question #4 above, we recommend elimination of R13.The 500 MW limitation discussed in the background section should be included in R11. There is no need to evaluate smaller islanding events.
Response: See SDT response to Q4 comment. The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
SERC SC UFLS Standard Drafting Team	No	As noted in our response to question #4 above, we recommend elimination of R13.The 500 MW limitation discussed in the background section should be included in R11. There is no need to evaluate smaller islanding events.

Organization	Yes or No	Question 13 Comment
Response: See SDT response to Q4 comment. The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
Southern Company Transmission	No	As noted in our response to question #4 above, we recommend elimination of R13.The 500 MW limitation discussed in the background section should be included in R11. There is no need to evaluate smaller islanding events.
Response: See SDT response to Q4 comment. The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
Progress Energy - Carolinas	No	As per our comment to Question #4, we recommend R13 be deleted. The 500 MW limitation discussed in the background section of the comment form should be included in R11. There is no need to require assessments for smaller islanding events.
Response: See SDT response to Q4 comment. The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
Northeast Power Coordinating Council	No	At present, the language in the implementation plan describes a one year phase in for compliance intended to provide Planning Coordinators sufficient time to develop or modify UFLS programs and to establish a schedule for implementation.NPCC has already developed an implementation plan. It must be noted that the NPCC implementation plan is a six year plan and the final language of the NERC implementation plan with regard to the overall approved term will have be closely monitored.
Response: Thank you for your comment. The schedule for implementation by UFLS Entities is at the discretion on the Planning Coordinator and is not set by the standard.		
MidAmerican Energy	No	MidAmerican notes that past under frequency event analyses are complex and that the minimum time frames for analysis and implementation should be increased to at least 2 years and exception requests for additional time should be allowed.
Response: One year ahould be sufficient for the majority of events.		
Duke Energy	No	R11 and R12 are okay, but R13 contains the problematic requirement to “reach concurrence”, as discussed in our responses to questions #2 and #4 above. Perhaps R13 could be revised to require affected Planning Coordinators to share event assessment results and respond to technical questions/comments within a

Organization	Yes or No	Question 13 Comment
		prescribed time period.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern		
AECI	No	R13 seems unreasonable. If we do everything in our power to concur with another planning coordinator and they do not concur, our compliance is then determined by somebody else's actions.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern.		
Bonneville Power Administration	No	Requirement R13 needs to rewritten because language is unclear, i.e. what is meant by "of UFLS actuated loss of load"?
Response: R13 was revised and the phrase, ". . . of UFLS actuated loss of load occurs. . ." was deleted.		
IESO	No	Small islands and frequency excursions below the initializing set points can result from recognized contingencies. In some cases, the island formed will be so small as to provide no meaningful evaluation for UFLS program effectiveness. Some additional guidance from the SDT is needed to define the nature of events that are intended to trigger an evaluation under R11.
Response: PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
Ameren	No	The intention of R13 is good but a provision should be provided for each Planning Coordinator to comply with R11 in the event that it is not feasible to satisfy R13 within the one year assessment period. The Planning Coordinator's compliance with R11 should not be dependent on actions by others.The 500 MW limitation discussed in the background section should be included in R11 to make sure this thought is not lost if/when the standard becomes effective. There is no need to evaluate smaller islanding events.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The 500 MW qualifier was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
SERC Planning Standards Subcommittee	No	The intention of R13 is good but a provision should be provided for each Planning Coordinator to comply with R11 in the event that R13 is not satisfied within the one year assessment period specified in R11. A Planning Coordinator's compliance with R11 should not be dependent on actions by other Planning Coordinators.The 500 MW limitation discussed in the background section should be included in R11. There is no need to

Organization	Yes or No	Question 13 Comment
		evaluate smaller islanding events.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The 500 MW qualifier was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
Tennessee Valley Authority (TVA)	No	TVA agrees with the intent of transitioning post-event analysis from PRC-009-0 to the proposed PRC-006-1 standard, but has the following comments:R11: The “500 MW or greater” threshold included in the background information should be included in R11.R13/M13: TVA has similar concerns with the requirement to reach concurrence with other affected PCs that are expressed in response to Question 11 for R5/M5. We recommend elimination of R13/M13, or the addition of language that would eliminate the compliance of a PC having dependency on the concurrence of one or more other PCs.
Response: The 500 MW qualifier was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern.		
Xcel Energy	No	We don’t believe these should be limited to islanding events. Suggest rewording to indicate that “events resulting in frequency excursions below initializing set points of the UFLS program, or actuate automatic switching or tripping shall ...”
Response: The purpose of automatic switching of capacitor bands, Tranmission Lines and reactors is to control voltage as a result of under frequency load shedding. This requirement was added to assist in recovery as a result of under-frequency load shedding.		
Exelon	Yes	
Indiana Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
Long Island Power Authority	Yes	
MEAG Power	Yes	

Organization	Yes or No	Question 13 Comment
NERC Staff	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
ReliabilityFirst Engineering Staff	Yes	
South Carolina Electric and Gas	Yes	
SPP System Protection and Control Working Group	Yes	
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
Tri-State Generation & Transmission Assoc.	Yes	Comments: The concept is correct but we believe an individual Planning Coordinator is the wrong entity to assess the operation and revise it. There is no clear jurisdiction for a PC. This should remain the responsibility of the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area.Why is “of UFLS actuated loss of load occurs” included in R13 but not in R11? It does not seem to add any information but does seem to unnecessarily complicate the requirement. This again seems like an argument for having the Regional Assurer involved because concurrence between Planning Coordinators is required. The language is unclear in R13 and should be re-written.
Response: The SDT believes the Planning Coordinator, having a wide-area view and the necessary technical skills, is the proper entity to oversee the design and implementation of UFLS. There is also wide industry support for the Planning Coordinator as the proper entity for UFLS. The Reliability Assurer has a very limited scope of activity in the Functional Model and is not a user, owner or operator of the BES. **R13 was revised and the phrase, “. . . of UFLS actuated loss of load occurs. . .” was deleted.**		

14. The industry identified a need for a variance for the Québec Interconnection within NPCC to address the physical characteristics of the Québec system. This variance allows frequency decline to be arrested at a lower threshold and higher frequency overshoot without jeopardizing reliability because the installed generation in the Québec Interconnection is 98 percent hydraulic. The variance also establishes a different capacity threshold for the generating units for which underfrequency and overfrequency trip settings must be modeled to address concerns that by 2020, 10 percent of the installed capacity in Québec may be located at plants less than 75 MVA. The SDT has proposed the variance that meets the needs of the Québec interconnection in the third draft of the standard. In particular SDT developed the variance to Requirement R3 parts 3.1 and 3.2 and Requirement R4 parts 4.1 through 4.6. The variance to these requirements reference separate under and overfrequency curves included as attachments 1A and 2A to the standard. Do you agree with this Variance?

Summary Consideration:

The standard drafting team received support for the variance. Several un-related comments were received and the standard drafting team provided responses to those comments below.

Organization	Yes or No	Question 14 Comment
MEAG Power		No comment.
Xcel Energy		No comments
Western Electricity Coordinating Council		The standard and performance requirements should reflect the individual interconnections and not a continent wide standard allowing for the uniqueness of each interconnection to be addressed similar to Hydro Quebec's variance.There is not a place to provide a response to question 15 from the unofficial word verison, so it is being provided here.Q 15While the concern for loss of additional generation units because of their V/Hz protection schemes is understood, the bases for the 1.18pu and 1.1pu values are not evident and may not be technically supportable when compared against actual protection settings or allowable post-contingency voltage bands. Further, V/Hz protection settings vary across the system and it is unlikely adherence to this requirement will impact reliability. It will only increase dynamic analysis requirements. We recommend removing R3.3.
Response: The V/Hz is derived from IEEE standards. The standard allows the Planning Corodinators within a region to work together to develop a		

Organization	Yes or No	Question 14 Comment
program accounting for the characteristics of each Interconnection or region. No change made.		
Tri-State Generation & Transmission Assoc.	No	Comments: The standard should adequately recognize the performance characteristics of different type of generation and a variance should not be required. Faster acting and greater inertia systems should be allowed the operating margins appropriate to their systems. Real differences exist between interconnections. The standard and its performance requirements should reflect this fact. This would allow for the uniqueness of each interconnection to be addressed similar to Hydro Quebec's variance.
Response: The standard allows the Planning Coordinators within a region to work together to develop a program accounting for the characteristics of each Interconnection or region. No change made.		
Bonneville Power Administration	No	The standard and performance requirements should reflect the individual interconnections and not a continent-wide standard. This would allow for the uniqueness of each interconnection to be addressed similar to Hydro Quebec's variance.Other Comments:While the concern for loss of additional generation units because of their V/Hz protection schemes is understood, the bases for the 1.18pu and 1.1pu values are not evident and may not be technically supportable when compared against actual protection settings or allowable post-contingency voltage bands. Further, V/Hz protection settings vary across the system and it is unlikely adherence to this requirement will impact reliability. It will only increase dynamic analysis requirements. We recommend removing R3.3.
Response: The standard allows the Planning Coordinators within a region to work together to develop a program accounting for the characteristics of each Interconnection or region. No change made.		
Ameren	Yes	
American Transmission Co.	Yes	
Entergy Services	Yes	
Exelon	Yes	
FirstEnergy	Yes	
IESO	Yes	

Organization	Yes or No	Question 14 Comment
Indiana Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
Long Island Power Authority	Yes	
MidAmerican Energy	Yes	
MRO's NERC Standards Review Subcommittee (NSRS)	Yes	
NERC Staff	Yes	
Northeast Power Coordinating Council	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Progress Energy - Carolinas	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC SC UFLS Standard Drafting Team	Yes	
South Carolina Electric and Gas	Yes	
Southern Company Transmission	Yes	

Organization	Yes or No	Question 14 Comment
SPP System Protection and Control Working Group	Yes	
Tennessee Valley Authority (TVA)	Yes	
United Illuminating Company	Yes	
Wisconsin Electric Power Company (dba We Energies)	Yes	
Y-W Electric Association, Inc.	Yes	
SERC Planning Standards Subcommittee	Yes	The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officiers.
Response: Thank you		
Manitoba Hydro	Yes	We are contemplating a variance. However, this variance must apply to other areas such as Manitoba Interconnection within MRO to address the physical characteristics of the Manitoba system. Manitoba system physical characteristics are very much similar to QuÃ©bec system. More than 90 % of installed generation in the Manitoba Interconnection is hydraulic. Manitoba Hydro may provide modifications to attachments 1B and 2B that would be applicable for Manitoba hydro area and cover UFLS program for an imbalance of more than 25%.
Response: Thank you. Variances requested will be reviewed.		
The California ISO	Yes	We request a WECC Regional variance for WECC to use its own set-points that are applicable to WECC members. (similar to what Hydro Quebec has done.)
Response: This comment process is not the method to request a variance. Variances requested will be reviewed.		

Consideration of Comments on Initial Ballot — Project 2007-01 — Underfrequency Load Shedding — Non-binding poll for VRF and VSLs
Date of Non-binding Poll: July 8-17, 2010

Summary Consideration: Many of the comments received indicated that until the SDT addressed the issues with the proposed standard support could not be offered for the proposed VRFs and VSLs. The SDT has made conforming changes to the proposed standards based on comments received during the posting and ballot of the standards that address many of the concerns. In addition, the SDT has addressed many of the suggested revisions to the VSLs proposed by commenters.

Many comments received in this poll indicated concern with the requirement to reach concurrence with other Planning Coordinators. The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen at 609-452-8060 or at Herb.Schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	1. R5 and R13 require that both or all the PC's reach concurrence on the assessment of the UFLS performance in an island. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. A standard should not require that one PC has to agree with another PC. 2. **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others.** R11 needs to have a MW size threshold for requiring the assessment of an UFLS event. As written, this requirement could require an assessment of an event where a breaker opened on a radial 115 kV line which had an 8 MW generator and 15 MW of load on the feeder.
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	
Gwen S Frazier	Gulf Power Company	3	Negative	
Don Horsley	Mississippi Power	3	Negative	

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				Such a small event has no consequence to the reliability of the BES. A MW threshold of 500 MW would be appropriate. **Response: PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. The existing standard PRC-009, which this standard is intended to replace, currently requires that an assessment be performed for all events regardless of size. The SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the requirement the same or better than what exists today.** 3. Miscellaneous improvements required to wording of R5, M5, and several VSL's. **Response: The SDT provided a detailed response to the suggested improvements in the Consideration of Comments report for the formal comment period conducted in June-July, 2010.**
Response:				
Jason Shaver	American Transmission Company, LLC	1	Negative	Although Draft 3 contains many significant improvements, there are still too many important issues that are not adequately addressed.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Mel Jensen	APS	5	Negative	Based on the negative vote on Project 2007-01 Underfrequency Load Shedding, the proposed VRFs and VSLs are rejected until the concerns with the proposed standard are addressed.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Robert D Smith	Arizona Public Service Co.	1	Negative	Based on WECC's 7/15/10 Position Paper for the ballot of Project 2007-01 - UFLS. "In addition to the ballot of PRC-006-1, a non-binding poll of the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is being conducted. Because of the recommended NO vote, members of the Underfrequency Load Shedding ballot pool are encouraged to reject the proposed VRFs and VSLs until such time that the concerns with the proposed standard are addressed".
Thomas R. Glock	Arizona Public Service Co.	3	Negative	
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	BC Hydro will not support the VRF and VSL document until such time as BC Hydro can support the UFLS standard Project 2007-01

Voter	Entity	Segment	Vote	Comment
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
John C. Collins	Platte River Power Authority	1	Negative	Because of the recommended NO vote on the standard, it would not make sense to approve the proposed VRFs and VSLs until such time the requirements of the standard are clarified.
Terry L Baker	Platte River Power Authority	3	Negative	
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	Can't vote yes on the VRF and VSL until the standard is at a point where I can vote yes for it.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	Comments associated with the negative vote are contained in the Project 2007-01 comment form submitted by TVA
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	Comments provided in comment form
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Russell A Noble	Cowlitz County PUD	3	Negative	Cowlitz cannot vote affirmative until it can also vote affirmative on the Standard as a whole.
Rick Syring	Cowlitz County PUD	4	Negative	
Bob Essex	Cowlitz County PUD	5	Negative	
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				

Voter	Entity	Segment	Vote	Comment
Joseph O'Brien	Northern Indiana Public Service Co.	6	Negative	EOP-003 It appears that there is, and always was, confusion with the use of "or" in EOP-003. For example in R5 the TOP or the BA shall implement a plan in steps. What if the TOP does this and the BA does not; is there a violation of the standard? This is not clear to me especially with BA/LBA JROs now in play. This could end up with "finger pointing" between the TOP and BA at audit time. In R4 it now states that voltage rate/level and power flow need to be considered when designing an automatic load shedding scheme. We have UFLS only and this appears to be a new requirement for us which may be a concern. Was that the intent? What does insufficient generation mean? Because the TOP or the BA shall shed customer load at this point according to R1. Does this mean when you're stuck at 59.98 Hz you should shed load, after all remedial steps? PRC-006 There are 22 pages of material to review and vote on; this is a bit overwhelming. Why not just work on the requirements first and leave the measurements for a later draft. It's too much. Applicability 4.3 is already covered in 4.2 There are Planning Coordinators within Planning Coordinators which makes it unclear who is responsible for all this compliance. It's not clear at all how a PC is to determine where islands are likely to occur.
Response: There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1. **The drafting team did not make any modifications to EOP-003, Requirement R4. This is an existing requirement, not something new.** **The SDT added this additional distinction for the purposes stated in Requirement R10. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** **The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.** **A Planning Coordinator must identify at least one island to be used as the basis for the R4 UFLS design assessment. However, this does not mean that islands must be identified from a Planning Coordinator's R1 criteria. As a minimum, the region or interconnection in which a Planning Coordinator's area is located must be identified as an island per R2.3.**				
Robert Martinko	FirstEnergy Energy Delivery	1	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote. Since we do not agree with the standard requirements and have cast a negative vote for the standard, we therefore do not agree with the VSL for the requirements as written.
Kevin Querry	FirstEnergy Solutions	3	Negative	

Voter	Entity	Segment	Vote	Comment
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Douglas Hohlbaugh	Ohio Edison Company	4	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote for the VRF for Requirement R1. Although we agree that Requirement 1 is important because it establishes a sound PSMP, a HIGH VRF assignment is not appropriate and it should be changed to LOWER. By definition, a requirement with a LOWER VRF is administrative in nature, and documentation of a program is administrative. Assigning a LOWER VRF to R1 is more logical since R4, which is the requirement to implement the PSMP, is assigned a MEDIUM VRF because, if violated, it could directly affect the electrical state or the capability of the bulk electric system.
Response: Requirement R1's VRF assignment is a Medium (not a High). The SDT thinks that this requirement is beyond administrative. It is important to the design of UFLS to develop and document criteria to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.				
Kenneth Dresner	FirstEnergy Solutions	5	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote. Since we do not agree with the standard requirements and have cast a negative vote for the standard, we therefore do not agree with the VSL for the requirements as written.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Mark S Travaglianti	FirstEnergy Solutions	6	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote for the standard as written. Although we agree that the Planning Coordinator is the appropriate functional entity to develop and implement a UFLS program, we are concerned with the fact that UFLS entities may not know the specifics of their responsibilities until long after this standard is approved. The SDT should consider adjusting the language of the standard to require more transparency and coordination with the UFLS entities during the PC's development of the UFLS program. Also, per the implementation plan, the PC will be given one year to develop its UFLS program. However, the timeframe for the UFLS entity is based on the schedule imposed by the PC. The implementation plan should allow the UFLS entity at least one year (maybe more per capital budget cycles) from the time the PC identifies the UFLS entity in their UFLS program. The UFLS entity will need sufficient lead time in those instances that require purchase of new UFLS equipment that will require long term budget planning for implementation. The UFLS entities are identified in the UFLS program established by the PC. However, it is not clear where the PC is explicitly required to notify and coordinate with the UFLS entity. In Requirement R3 it is implied that the PC will notify and coordinate with the UFLS entity per the phrase "including a schedule for implementation by UFLS entities within

Voter	Entity	Segment	Vote	Comment
				its footprint". This requirement needs to be more explicit that the PC will notify the UFLS entity, and the measure for R3 needs to require proof that the PC has done this. **Response: The SDT agrees that UFLS Entities should have opportunity to provide input to the Planning Coordinator on what will be required of them.** **The SDT added a requirement to the proposed standard, Requirement R14, to ensure that the Planning Coordinators collect and respond to comments submitted by UFLS entities on the UFLS program, including a schedule for implementation and UFLS design assessment.** We are concerned about the coordination between this UFLS SDT and the GV SDT. It will be difficult to approve and begin implementing the PRC-006-1 standard while the PRC-024-1 standard is still under development and scheduled for approval and implementation at a much later date. For these requirements to be adequately coordinated, the two standards need to be developed, balloted and implemented at the same time. Alternatively, consider adding the following statement in the PRC-006-1 Implementation Plan: "The Effective Date and implementation of this PRC-006-1 standard requires coordination with standard PRC-024-1. Excluding requirement R1, the Effective Date of PRC-006 shall be the later of 1) the completion of the Implementation Plan for PRC-006 or 2) the completion of the Effective Date of the PRC-024-1 standard upon completion of its Implementation Plan." **Response: Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.**
Response: Please see in-line responses.				
James A Ziebarth	Y-W Electric Association, Inc.	4	Negative	From question 3 on the comment form: Regarding the VSLs for R8, the UFLS entities cannot be punished for failing to meet a schedule if the schedule is not mutually agreed upon between the Planning Coordinator and the UFLS entities to ensure that the UFLS entities are capable of meeting such a schedule. At the very least, there must be some protection for the UFLS entities provided that requires the Planning Coordinator(s) to give the UFLS entities long-term notice of the deadlines that they will need to meet. The lack of any scheduling restrictions for the Planning Coordinators in the standard as written has a strong potential to cause enormous burdens on small UFLS entities that simply do not possess the resources to deal with such data reporting requirements without sufficient advance notice. Additionally, the UFLS entities cannot be penalized for failing to submit data in a format over which they have no control or input. The Planning Coordinator should be required to consult with the UFLS entities and decide upon a mutually agreeable data format in order to ensure that the UFLS entities are capable of providing the required data in the required format.

Voter	Entity	Segment	Vote	Comment
				With no language in the standard limiting or clarifying what data can be required of the UFLS entities by the Planning Coordinator, this provision at least should be made to protect small UFLS entities with highly limited resources for dealing with such data reporting requirements.
Response: The SDT added a requirement to the proposed standard, Requirement R14, to ensure that the Planning Coordinators collect and respond to comments submitted by UFLS entities on the UFLS program, including a schedule for implementation and UFLS design assessment.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	It is unclear from the Standard that not forming islands in UFLS design is acceptable. Recommend the SDT consider including language to clarify that is not mandatory that system islands by formed in every UFLS design configuration.
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Scott Heidtbrink	Kansas City Power & Light Co.	5	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Response: The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. To this end, Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. These islands are to be used in UFLS design assessments and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordinate UFLS plans within a region. There are no requirements to identify Planning Coordinator footprints as islands, but all of a Coordinator's area will be included in one island or another.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	No VRF for UFLS should be High. UFLS is only actuated because several other things did not work properly. For a VRF to be High, there must be a direct causal link to bad things happening (i.e. cascading, instability, blackout) as result of the requirement. If UFLS has to be actuated, we have already reached the bad things happening stage and this represents a last ditch effort to save the system because several immediate steps did not prevent the bad things from happening.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.				

Voter	Entity	Segment	Vote	Comment
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	NPCC has already implemented a Region specific UFLS Program incorporating a six year UFLS implementation plan, with year one of the plan having ended June, 2010. As such, Con Edison is concerned with how this version of PRC-006 might impact the NPCC Regional UFLS Standard. PRC-006 is not applicable to generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved.
Response: The schedule for implementation by UFLS Entities is at the discretion on the Planning Coordinator and is not set by the standard. The SDT has clarified in the effective date of PRC-006 that the sub-parts related to modeling of generator trip settings will not be effective until PRC-024 is approved and effective. Adding a Generator Owner data requirement to PRC-006 would be redundant and cause double jeopardy concerns. It is the case that some standards are dependent on data requirements found in other standards. An example is that data necessary to comply with TPL standards is required under MOD standards.				
Louise McCarren	Western Electricity Coordinating Council	10	Negative	Opposed to the standard as drafted, so voting against associated VRFs and VSLs Comments submitted will provide specific details
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Lee Schuster	Florida Power Corporation	3	Negative	Progress Energy believes that, overall, the proposed version of NERC Standard PRC-006-01 is acceptable and will provide good direction to the industry. However, we are voting Negative in this ballot, pending resolution of a number of comments that have been submitted via the on-line comment form. The major areas of concern are as follows. 1. Requirements R5 and R13 require two or more Planning Coordinators to "reach concurrence" on UFLS design assessment results. However, no process is provided for resolution if concurrence cannot be reached. 2. Requirement R11 needs to have a threshold such that it is not necessary to perform mandated assessments of smaller islanding events. We suggest a threshold of 500 MW of load, as discussed in the Background discussion section of the Comment Form. 3. Several of the Violation Severity Levels are overly severe regarding assessment studies being late and/or they do not appropriately include a time frame as part of the measure. See the formal comments provided separately by Progress Energy for more details.
Wayne Lewis	Progress Energy Carolinas	5	Negative	
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. **The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertently was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. The existing standard PRC-009, which this standard is intended to replace, currently requires that an assessment be performed for all events regardless of size. The SDT cannot remove a requirement from an existing**				

Voter	Entity	Segment	Vote	Comment
standard without a technical justification that explains how this will make the requirement the same or better than what exists today. **Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.**				
Mark Ringhausen	Old Dominion Electric Coop.	4	Negative	R4- REquieres conncurence amongst PCs(maybe in different regions) how do you deteremine whom is non-compliant. **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. The revised standard eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.** What does 'design assessement' mean? **Response: A design assessment is an assessment of the UFLS program design to ensure that the UFLS program meets the performance characteristics (Requirement R3).** R5- What does the SDT meand by 'concurrence' in the requirement? This needs to be clarified. **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern – the term is no longer used. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments.** R12- What do you mean by 'consider' the deficiencis? Must they be resolved? If you mean the PC must resolve them, the say that as 'consider' does not mean this. **Response: An event may reveal that a UFLS program, while compliant with R3, might yet have performed better during the specific event under study. A design assessment is required by R12 to consider any conclusions or recommendations (deficiencies and how to address them) identified in the R11 event assessment relevant to the specific event while maintaining R3 compliance. However, as long as the UFLS program is compliant with R3, the standard cannot require resolution of such deficiencies.**

Voter	Entity	Segment	Vote	Comment
Response: Please see in-line responses.				
Harold Taylor, II	Georgia Transmission Corporation	1	Negative	R5: Need a measure for concurrence. Can two PCs have differing UFLS practices but still attain the needed load shed or must both have the same set point criteria to be in concurrence? **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. The standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area.** R7: While 40 calendar days for the Lower VSL is acceptable, the remaining 10 day intervals should be "working" days. **Response: The SDT thinks that calendar days are appropriate for the 10-day intervals to be consistent with the Lower VSL.** R8: Calendar days should be "working days". Mixing time limit and acceptable PC database format as a penalty can be subjective. **Response: The SDT thinks that calendar days are appropriate; working days are not always the same for everyone. Both time limit and format need to be included somehow in the VSLs. The SDT believes the mix is appropriate.** R11: Lower VSL is an incomplete statement. Delete "to evaluate" from the end. **Response: The SDT made modified the VSL for Requirement R11 by making it a complete statement and replaced “to evaluate” with “evaluated”.**
Response:				
Douglas E. Hils	Duke Energy Carolina	1	Negative	Requirements R5 and R13 contain the problematic requirement to “reach concurrence”, as discussed in our responses to the comment form. The VSLs for these requirements is a solitary Severe VSL which may be impossible to meet, if an entity refuses to reach concurrence.

Voter	Entity	Segment	Vote	Comment
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. The SDT modified both R5 and R13 and made conforming changes to the VSLs. The revised standard eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.				
David Schiada	Southern California Edison Co.	3	Negative	SCE supports WECC's position paper.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots				
Anthony Jankowski	Wisconsin Energy Corp.	4	Negative	see comments on standard
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots				
Tom Bowe	PJM Interconnection, L.L.C.	2	Negative	The ability for the PC to comply with R1 and R2 requires ULFS entities and Transmission Owners to comply with this standard. The VSLs should clearly state that it is the PC who did not meet its obligations under R1 and R2 and not that non-compliance to R1 and R2 was the result of non-compliance by a third party which the PC relied on in meeting its obligations under this standard.
Response: Requirements R1 and R2 of the proposed standard do not involve the Transmission Owners or UFLS entities to perform a task in order for the Planning Coordinators to comply with the requirement. The proposed requirements (R1 and R2) relate to the determination of islanding criteria and the identification of islands in the planning horizon for use in UFLS design assessments. The activities in Requirements R1 and R2 are planning activities that can be accomplished without a Transmission Owner or UFLS entity.				
Laurie Williams	Public Service Company of New Mexico	1	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within a Reliability Region as there are Planning Coordinators. Additionally, the proposed standard does not address UFLS relays which are currently part of the existing program but are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall

Voter	Entity	Segment	Vote	Comment
				into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard requires the identification of Regional Entity footprints as islands to be used in UFLS design assessments (Requirement R2, Part 2.3) and that the Planning Coordinators within each Regional Entity footprint work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within an interconnnection. The SDT believes that a continent-wide standard cannot require single UFLS plans for each interconnection. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design. **Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.**				
Bruce Merrill	Lincoln Electric System	3	Negative	The majority of VSLs and VRFs are acceptable as currently proposed. However, the VSLs for R5 and R13 depend on reaching "concurrence" with other entities, which is not a valid basis for measuring compliance. If the concurrence requirement cannot be revised, then we propose that the VSL levels be reduced. **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. The revised standard eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.** Additionally, we would propose reducing the VRFs for R3, R4, R9 and R10 from "High" to "Medium" to account for the fact that primary measures of automatic UFLS programs will normally restore the system even if some UFLS requirements are not completely fulfilled. **Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency,**
Dennis Florom	Lincoln Electric System	5	Negative	
Eric Ruskamp	Lincoln Electric System	6	Negative	

Voter	Entity	Segment	Vote	Comment
				abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.
Response: Please see in-line responses.				
John T. Underhill	Salt River Project	3	Negative	The primary concern identified is that the current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed, the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered, the LSE needs to be included in the Applicability section. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Glen Reeves	Salt River Project	5	Negative	
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard requires the identification of Regional Entity footprints as islands to be used in UFLS design assessments (Requirement R2, Part 2.3) and that the Planning Coordinators within each Regional Entity footprint work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within an interconnection. The SDT believes that a continent-wide standard cannot require single UFLS plans for each interconnection. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE				

Voter	Entity	Segment	Vote	Comment
in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. **The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design.** **Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.** **The curves are solely for checking the frequency trajectories of simulations and not for setting UFLS relays. The Quebec interconnection has a variance. The other three interconnections are not unique enough to have separate curves, though they could propose variances if they wanted to. They have not. The Planning Coordinators do have the responsibility to determine UFLS design parameters including frequency set points. The SDT decided in the first draft that these parameters should not be determined in a continent-wide standard for the very reason that regions and interconnections have unique characteristics. This is decidedly not a least common denominator approach. The SDT disagrees that the performance characteristic curve approach is reverse engineering, but rather designing to a target. The reliability justification for the curves is their coordination with generator tripping.**				
Dennis Sismaet	Seattle City Light	6	Negative	The standard, requirements, and measurements should reflect the uniqueness of the individual interconnections and not common, continent wide prescriptions.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs.				
John Tolo	Tucson Electric Power Co.	1	Negative	The WECC's Underfrequency Load Shedding Plan is done on an interconnection-wide basis and therefore should have a regional variance as the Quebec Interconnection has. Further, until the WECC has a defined Planning Coordinator this standard, as written, may be applicable to each Balancing Authority's Planning Authority.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots. The terms, "Planning Authority" and "Planning Coordinator" are accepted as identical by both NERC and FERC.				
Larry Akens	Tennessee Valley Authority	1	Negative	TVA believes the following VRF changes should be considered: R4 - change from High to Medium. Justification: The selection of a 5-year interval for assessments seems subjective in nature. Failure to perform an assessment within a 5-year interval would not directly cause or

Voter	Entity	Segment	Vote	Comment
George T. Ballew	Tennessee Valley Authority	5	Negative	contribute to bulk electric system instability. **Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.** R11 - change from Medium to Low. Justification: documenting a post event assessment seems more administrative in nature, relative to R12. **Response: Requirement R12 requires that a post event assessment be conducted as well as documented. If the requirement was only a documentation requirement then the VRF should be a "lower"; however, there is more to the requirement than just documentation.** The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. **Response: The SDT made conforming changes to the VSL for Requirement R11.** Recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that grading the timeliness of the study is necessary. The SDT established increments in the VSLs according to the NERC VSL guidelines.** Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented." **Response: The SDT made conforming changes to this VSL.** The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.).

Voter	Entity	Segment	Vote	Comment
				Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that grading the timeliness of the study is necessary.
Response:				
John Canavan	NorthWestern Energy	1	Negative	Voted no to the proposed standard
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Gregory J Le Grave	Wisconsin Public Service Corp.	3	Negative	VRF's for R4 should be reduced from "high" to "medium". System events that would cause UFLS program initiation are rare and are a last resort to preserve the interconnection. The performance of an UFLS program does not change dramatically enough to warrant a "high" VRF for a delay in conducting or documenting a UFLS assessment. **Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.** VSL for R9 is too restrictive. Distribution Providers, particularly small ones, will find it onerous to attempt to manage distribution circuit loads within such tight requirements on its UFLS feeders. **Response: Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. The Planning Coordinator will need to take into account the ability and limitations of small Distribution Providers to allocate load for UFLS. The Distribution Provider can comment on the Planning Coordinator's UFLS program design in this regard via the provision of Requirement R14 peer review.**
Response:				

Voter	Entity	Segment	Vote	Comment
Janelle Marriott	Tri-State G & T Association Inc.	3	Negative	We believe that individual Planning Coordinators are not the appropriate entities to be responsible for determining criteria for areas that may form islands, for identifying the islands, for developing the UFLS program for periodic assessments, for maintaining databases or for assessing events. The current registration by numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. All Planning Coordinators within an interconnection should be required to collaboratively develop an interconnection-coordinated UFLS Plan. Further, Planning Coordinator footprints are neither defined nor is there any guidance on how they should be established. Every VSL that refers to a PC footprint should be clarified. The primary purpose of any UFLS program should is to mitigate the need to form islands by balancing total system loads and resources. It is only a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding events rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts within the interconnection. We strongly believe that there should be recognized sub-area group(s), which consist of PCs, as assigned by the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate or address the interconnection reliability needs There is also a concern that EOP-003-2 is currently being balloted based on changes made as a part of the Order 693 Directives. The two versions are not compatible. We believe that “ownership” should be removed from the criteria because it may be different from the operating or controlling entity and both entities cannot be responsible. Load Serving Entities should also be included as a “possible” UFLS entity. Some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. Each interconnection should establish discrete set points based upon stability and dynamic analysis. From discrete set points one can establish criteria which are measurable and performance based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC. Furthermore, the Standard needs to be very explicit that the curves are interconnection performance curves and not specific protective relay set points. The standard should adequately recognize the performance characteristics of different type of generation and a variance should not be required. Faster acting and greater inertia systems should be allowed the operating margins appropriate to their systems. Real

Voter	Entity	Segment	Vote	Comment
				differences exist between interconnections. The standard and its performance requirements should reflect this fact. This would allow for the uniqueness of each interconnection to be addressed similar to Hydro Quebec's variance.
Response: The SDT believes the Planning Coordinator, having a wide-area view and the necessary technical skills, is the proper entity to oversee the design and implementation of UFLS. There is also wide industry support for the Planning Coordinator as the proper entity for UFLS. The SDT recognizes the need to at least preserve coordination on the regional level and has inserted a requirement (Requirement R2, Part 2.3) to identify each Regional Entity footprint as an island to be assessed for UFLS performance. The PC's within each region will need to work with each other in order to produce a successful assessment. **The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.** **The scope of work addressed under the Order 693 Directives was revised so that Project 2010-12 no longer addresses EOP-003.**				
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	We cannot vote affirmative on the VRFs and VSLs until concerns on the proposed standard have been addressed.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Charles H Yeung	Southwest Power Pool	2	Negative	We disagree with the enforcement of requirements if a subject registered entity will have to rely on another yet to be approved standards to be fully compliant. A generator/owner operator must be held responsible to provide UFLS data to the PC. The SDT has denied a request to add GOs into the PRC-006 citing such a requirement falls outside the scope of this standard and will be addressed in a separate standard. Nonetheless, adoption of this version of PRC-006 will subject PCs to account for all bulk power system devices that affect UFLS schemes, but lacks the ability to force a GO to provide needed data. NERC compliance must realize such gaps exist and enforce these requirements with that knowledge. These VSLs do not recognize such a gap.
Response: The responsibility of generator owners resides within a standard under development currently, PRC-024. Per the implementation schedule proposed for PRC-006, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.				
Richard J. Padilla	Pacific Gas and Electric Company	5	Negative	We have voted no due to our negative vote on the standard recommend that the VRF and VSL be addressed after the standard comments are resolved
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				

Voter	Entity	Segment	Vote	Comment
Paul B. Johnson	American Electric Power	1	Affirmative	As AEP has stated in other projects, setting a VSL at "Severe" for a binary outcome could be challenged as being arbitrary and another level should be used as the starting point.
Edward P. Cox	AEP Marketing	6	Affirmative	
Response: In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use specific guidelines for determining whether to approve VSLs: Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties A violation of a "binary" type requirement must be a "Severe" VSL. The SDT must comply with the FERC VSL guidelines.				

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Project 2007-01 Underfrequency Load Shedding
Date of Initial Ballot: July 7-17, 2010

Summary Consideration:
During the third posting of PRC-006-1 and EOP-003-2 the standard drafting team made several conforming changes as a result of the industry comments received.

The fourth version of the proposed standard addresses the coordination issue many commenters expressed. Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.

Commenters expressed confusion over having Transmission Owners as part of UFLS Entities but separated out as Transmission Owners in Requirement R10 and suggested combining R9 and R10. The team reviewed the rationale for this structure. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements.

Commenters expressed that the wording in Requirement R10 “switching of elements” is confusing. The team modified Requirement R10 to clarify that it means: “switching of capacitor banks, Transmission Lines, and reactors” in order to control over voltage as a result of under frequency load shedding.

Many commenters indicated that Generator Owners should be included in the applicability of the standard. Some suggested including a data requirement in PRC-006-1 that requires the Generator Owners to submit the necessary data to accomplish Requirement R4; however, the team felt that because such a data requirement already exists in PRC-024 and because the team has clarified in the effective date of the standard that the sub-parts related to generators will not be effective until PRC-024 is approved and effective that adding such a data requirement to PRC-006 would be redundant and possibly cause double jeopardy concerns.

The standard drafting team received several comments on EOP-003 that expressed concern that the removal of under-frequency load shedding in the standard was not clear enough. The standard drafting team made modifications to the EOP-003 requirements that clarify that the load shedding referred to in the requirements exclude automatic under-frequency load shedding.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	(1) PRC-006, R1 should be modified such that PC is required to coordinate development of the islanding criteria in consultation with TO and TP. Further, presently the RE is involved in performing or coordinating the islanding/UFLS studies. We believe that RE should continue to be involved. (2) PRC-006, R2.3 No basis provided for criteria included in the second part of R2.3; that is, each RE footprint that resides in the PC footprint is to be identified as an island. (3) EOP-003-1, R2, the last phrase should be modified from "...load shedding scheme is required." to "...load shedding scheme is necessary to minimize the risk of uncontrolled failure of the interconnected system to match the "Purpose" of the standard.
Response: Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model version 5.				
George T. Ballew	Tennessee Valley Authority	5	Negative	"Comments associated with the negative vote are contained in the Project 2007-01 comment form submitted by TVA."
Response: Please see our response to your comments.				
Henry Delk, Jr.	SCE&G	1	Negative	1) SCE&G proposes an effective date of 24 months after regulatory approval. We believe the currently proposed effective date of 12 months after regulatory approval would not allow enough time to ensure compliance due to the requirements to establish criteria to identify islands, coordinate results with other Planning Coordinators, and reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion. A number of these requirements cannot be met until a prior requirement is completed and each of these requirements requires coordination with other utilities which will increase the amount of time necessary to obtain compliance. As a result, SCE&G believes an effective date of 24 months after regulatory approval would be much more practical and desirable than the currently proposed 12 month effective date. **Response:** The standard drafting team received feedback that many of the existing UFLS programs meet the performance characteristics in the proposed standard. Once this standard is approved the entities with existing programs would need a year to validate their program and validate the schedule for implementation with the UFLS entities. 2) The graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a
Matt H Bullard	South Carolina Electric & Gas Co.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curves data points. **Response:** The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	1. R5 and R13 require that both or all the PC's reach concurrence on the assessment of the UFLS performance in an island. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. A standard should not require that one PC has to agree with another PC. **Response:** The standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model version 5. 2. R11 needs to have a MW size threshold for requiring the assessment of an UFLS event. As written, this requirement could require an assessment of an event where a breaker opened on a radial 115 kV line which had an 8 MW generator and 15 MW of load on the feeder. Such a small event has no consequence to the reliability of the BES. A MW threshold of 500 MW would be appropriate. 3. Miscellaneous improvements required to wording of R5, M5, and several VSL's. **Response:** PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	
Gwen S Frazier	Gulf Power Company	3	Negative	
Don Horsley	Mississippi Power	3	Negative	
Response:				
Bruce Merrill	Lincoln Electric System	3	Negative	Although Draft 3 contains many significant improvements over previous drafts, LES believes the standard can be further refined to incorporate important issues that are not adequately addressed at this time. Please see the MRO NSRS group comments for LES'

Voter	Entity	Segment	Vote	Comment
Dennis Florom	Lincoln Electric System	5	Negative	specific concerns. **Response:** The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.
Eric Ruskamp	Lincoln Electric System	6	Negative	
Linda R. Jacobson	City of Farmington	3	Negative	Another concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.				
Gregory Campoli	New York Independent System Operator	2	Negative	Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved. This standard seems to be contrary to FERC's stated concern (Oct. 2009 Washington DC meeting) to develop a standard that can support the program it was designed to enforce.....the applicability as stated in the standard and by NERC registry criteria restricts and excludes the need for GO's that may in aggregate be necessary for a reliable UFLS program, to adhere to the standard. The standard also is potentially in conflict with the work being done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. Sufficient coordination on NERC Standards development needs to occur on a going forward basis.
Response: The suggestion to include the Generator Owners in the proposed standard is problematic because such a data requirement already exists in PRC-024 and because the team has clarified in the effective date of the standard that the sub-parts related to generators will not be effective until PRC-024				

Voter	Entity	Segment	Vote	Comment
is approved and effective that adding such a data requirement to PRC-006 would be redundant and possibly cause double jeopardy concerns.				
Jason Shaver	American Transmission Company, LLC	1	Negative	ATC is voting negative for the following reasons. These comments were submitted in our NERC comment form. M5 - As noted in the comments below for R5, replace the words "reached concurrence with" with "provided a UFLS design assessment report to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors. M7 - As noted in the comments below for R7, replace "within their Interconnection", with "that have design assessment responsibilities within the islands covered by the UFLS database". Planning Coordinators that are within the same Interconnection, but are not within any islands covered by another Planning Coordinators UFLS database, would not need to receive the UFLS information. M10 - Replace "automatic switching of Facilities" with "automatic switching of Elements" to be consistent with the associated Requirement R10. We propose that the scope of the SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for also removing the automatic UVLS requirements from EOP-003-1 and referring them to a new PRC standard. In line with the comments for Question 6: R2 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and new PRC standard. R3 - add the qualification "coordinate manual load shedding plans". R4 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard. R5 - add the qualification "implement manual load shedding plans". R7 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard. 1. In R3, the term, "imbalance", should be described using the standard industry nomenclature of imbalance = (load-generation)/generation. 2. In R4, we interpret that the Equivalent Inertia Analysis is a valid dynamic simulation methodology for certain aspects of UFLS assessments. So, we expect that this type of dynamic analysis would be accepted toward compliance with the "through dynamic simulation" portion of this requirement Attachement 1 for R4.1, R4.2, R4.3 3. The title for Attachment 1 should clearly qualify that this curve applies for a 25% or less island imbalance. The curves that should be used for UFLS programs associated with imbalance levels greater than 25% (e.g. 30%, 40%, 50%) would be different from the 25% curve. 4. The Under Frequency Performance Characteristic line in Attachment 1 should be extended to 59.5 Hz (at 500 sec). The reason for this change is that the worst case response between 58.7 Hz and 59.5 Hz may occur for imbalance conditions significantly less than 25% where the governor response prevents the load shedding blocks from

Voter	Entity	Segment	Vote	Comment
				picking up and where response recovery times is a function of governor response and system inertia (30 seconds to 500 seconds). This removes the knee of the curve at 30 seconds and extends the curve up to 500 seconds. This would change the 30 second at 58.9 Hz cut off point to 500 seconds. 5. Add a note to Attachment 1 that states, "Larger size UFLS programs (e.g., 40%) may require less restrictive (lower and/or longer time delays) underfrequeny limits due to island generation and protection characteristics." UFLS programs shedding more than 25% must increase generation protection delay times and/or change set points to achieve coordination with load shedding. For example, Manitoba Hydro and Saskatchewan need to shed more than 30% of the area load to achieve reasonable frequency recovery in their islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable. Attachment 2 for R4.4, R4.5, R4.6 6. The title for Attachment 2 should clearly qualify that this curve applies for a 25% or less island imbalance. The curves that should be used for UFLS programs associated with imbalance levels greater than 25% (e.g. 30%, 40%, 50%) would be different from the 25% curve. Generator Underfrequency and Overfrequency Attachments 7. The Generation Owner off-nominal frequency coordination requirements and coordination curves should be included in the PRC-006 standard. The generation curves should be applicable for load shedding levels beyond the 25% (e.g. 30%, 40%, 50%). If curves beyond 25% are not include, then the titles of the curves should qualify that they apply for 25% imbalance and include an note regarding coordination with UFLS programs that shed higher than 25% of the island load. The line should extend to 57 Hz (at .3 sec) to 59.5Hz (at 1800 sec). The minimum frequency of 57.0 Hz was chosen because most conventional generation can briefly operate down to 57.0 Hz and large load shedding programs may need to make use of that capability to achieve coordination with these UFLS programs. Volts/Hertz Performance Characteristic 8. The Volts/Hz requirement should be removed. This performance characteristic cannot presently be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation. In addition, the Volts/hertz requirement is not need in this standard. Voltage regulators automatically reduce voltage according to volts per hertz when in the automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist that adequately address the volts/Hz issue. Replace the words “reach concurrence with” with “provide UFLS design assessment results to”. Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words “other affected Planning Coordinators” with “other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of “other affected Planning Coordinators” is too vague and could be interpreted and categorized differently by various

Voter	Entity	Segment	Vote	Comment
				entities and auditors. Consideration should be given to replacing “Transmission Owner” with “UFLS Entity” because the automatic switching of distribution Elements (e.g. capacitor banks) may be more effective and practical UFLS design than restricting the scope of the requirement to just transmission Elements. 1. For R11, replace “Each Planning Coordinator, in whose footprint . . . to evaluate” with “When a disturbance event occurs in a Planning Coordinator’s footprint that involves automatic UFLS program operation or frequency excursions should have activated UFLS program operation, and a final disturbance report is required per EOP-004, each Planning Coordinator shall evaluate within one year of the disturbance event:”. 2. Either part of or after R11, there should be a requirement that “Each Planning Coordinator shall provide a preliminary event assessment report to the other Planning Coordinators who must conduct an assessment of the event for review at least 90 days before finalizing the event assessment report. 3. For R13, replace “in whose footprint . . .on the event assessment result” with “that conducts an UFLS design assessment (per R12) for islands where other Planning Coordinators have design assessm
Response: Please see our responses to your comments in the consideration of comments report.				
Scott Kinney	Avista Corp.	1	Negative	Avista has the following comments o The proposed standard fails to address UFLS relays which are currently part of the program which are owned by the customer. This is critical to have a successful program. In addition the UFLS- DT believes to assure areas are covered the LSE needs to be included in the Applicability section. **Response:** The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; “For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. o EOP-003-1 or the proposed EOP-003-2 and the proposed PRC-006 both address automatic UFLS -- only one standard should address the automatic UFLS -- two standards lead to confusion and potential double jeopardy. **Response:** The standard drafting team made modifications to the EOP-003 requirements that clarify that the load shedding referred to in the requirements excludes automatic under-frequency load shedding. o The proposed measures are vague, not specific and not performance based which leave too much up to the Auditor’s interpretation. **Response:** The SDT thinks that the Measures identify the evidence or types of evidence needed to demonstrate compliance with the associated requirement. The SDT thinks that the commenter is proposing that the SDT propose the RSAW not the Measures.

Voter	Entity	Segment	Vote	Comment
				o The proposed requirements are not well defined and are hard to apply in some cases, which leads to a problem with the proposed "Violation Severity Levels". Unclear and not well defined requirements cause a disconnect with the Violation Severity Levels. o The proposed standard does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. **Response:** The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard. o The primary purpose of the UFLS Plan is designed to mitigate the need to form islands by balancing loads and resources. It is a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding event rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs effort within the interconnection. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. o The WECC UFLS-DT believes there should be recognized sub-area groups, (consisting of PCs, as assigned by the Reliability Assurer (RA)). These sub-groups would be the agent for the PCs, and would assure the overall coordination within the interconnection. For example, the WECC RA recognizes the following sub-areas for UFLS coordination within the Western Interconnection (WI): Southern Islanding Load Tripping Group, the Northwest Power Pool UFLS group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-groups, PCs could randomly form sub-area groups whose plans may not coordinate on an interconnection wide basis or even address the interconnection reliability needs, but coordinated among the randomly formed sub-groups. **Response:** Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and

Voter	Entity	Segment	Vote	Comment
				conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. o The proposed standards attempt to establish a continent wide with frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.
Claudiu Cadar	GDS Associates, Inc.	1	Negative	Besides the commented answers to the NERC questions within the comment form, GDS Associates has the following additional comments as follows: - Effective Date. Depending on when this standard is mandatory and enforceable, it may fall between entities' budgeting periods. An 18 months implementation would allow for all entities to budget the funds necessary to implement the standard. **Response:** The standard drafting team received feedback that many of the existing UFLS programs meet the performance characteristics in the proposed standard. Once this standard is approved the entities with existing programs would need a year to validate their program and validate the schedule for implementation with the UFLS entities. - Requirement R8. How the UFLS entity suppose to provide data to the Planning Coordinator and when is suppose to do that? The Planning Coordinator can make its UFLS database available within 30 days upon request (see Requirement R7.) **Response:** The standard drafting team added a requirement to the proposed standard to collect and respond to comments on the UFLS program, schedule for implementation and for the collection of data for the UFLS database (Requirement R14). - Requirement R9, R10. What if the UFLS entity does not agree with Planning Coordinator's assessment? - Requirement R10 should be further elaborated - Measure M10. There is no BES term for "automatic switching". The measure should be reworded

Voter	Entity	Segment	Vote	Comment
				for a clear understanding. **Response:** The standard drafting team added a requirement to the proposed standard to collect and respond to comments on the UFLS program, schedule for implementation and for the collection of data for the UFLS database (Requirement R14). The team modified Requirement R10 to clarify that it means: "switching of capacitor banks, Transmission Lines, and reactors" in order to control over voltage as a result of under frequency load shedding.
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	Comment: NPCC has already implemented a Region specific UFLS Program incorporating a six year UFLS implementation plan, with year one of the plan having ended June, 2010. As such, Con Edison is concerned with how this version of PRC-006 might impact the NPCC Regional UFLS Standard. Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved.
Response: The standard drafting team provided clarifying examples in the implementation schedule to clarify that entities with existing programs and schedules for implementation will need to validate their existing programs against the standard's requirements and collect feedback from the UFLS entities as required by the standard.				
Larry Akens	Tennessee Valley Authority	1	Negative	Comments associated with the negative vote are contained in the Project 2007-01 comment form submitted by TVA
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	
Response: Please see our response to your comments in the consideration of comments report.				
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	comments provided on comment form
Response: Please see our response to your comments in the consideration of comments report.				
Robert W. Roddy	Dairyland Power Coop.	1	Negative	concerned that generation limits are too conservative.
Response: Please see our response to your comments in the consideration of comments report.				
Russell A Noble	Cowlitz County PUD	3	Negative	Cowlitz believes the comments of BPA and WECC concerning the current draft of the Standard need to be addressed before a positive vote can be cast.

Voter	Entity	Segment	Vote	Comment
Rick Syring	Cowlitz County PUD	4	Negative	**Response:** Please see our response to your comments in the consideration of comments report. One troubling aspect is the current ownership of UFLS relays by end-use customers, put in place during the voluntary compliance reliability era. These relays, buried deep into the customer's plant is necessary to allow safe load shedding. Placing the relays in the Distribution Provider's facilities is not possible without compromising the safety of plant personnel or the loss of significant plant product and equipment due to an uncontrolled plant shut down. In such situations, it is not palatable to require end-use customers to register; it is also not fair to force the Distribution Provider to negotiate with the customer, assuming the DP and LSE are not the same entity. Therefore, it is the LSE who must deal with the customer and the subsequent negotiation of contract agreements for the maintenance of customer owned equipment necessary for UFLS. It must be strongly noted that the LSE should not be required to own, or maintain the equipment. The LSE can only act as the reliability emissary in negotiating with the customer in this regard, however it is difficult to pass on any consequence of reliability violations to the customer. Should the customer be remiss in the upkeep of the relays, the LSE is then subject to compliance penalties over actions it has little control of. Also keep in mind of the complexity of PRC-005-2 applicability to the customer's electrical facilities due to the UFLS relay present there. This is truly a compliance nightmare of great concern to Cowlitz. **Response:** The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.
Bob Essex	Cowlitz County PUD	5	Negative	
Paul Morland	Colorado Springs Utilities	1	Negative	CSU offers the following comments: R3 (Attachments) It is not clear how attachment 1 should be used. Are the curves performance curves? Set point curves? R10 Need more clarity on what is meant by "Automatic Switching of Elements"? Does it mean a TO needs to automatically switch capacitor banks to avoid overvoltages?
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.				
John K	Dominion Virginia	1	Negative	Currently there is no requirement for Generator Owners to provide trip settings for non-

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Loftis	Power			conforming units to the Planning Coordinator. Absent such a requirement, the responsibility for compliance would be placed on the Transmission Owner. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. So, we suggest the addition of a requirement (applicable to the Generator Owner) to provide the information (as needed in R3-R3.3.3) to the Planning Coordinator.
Michael F Gildea	Dominion Resources Services	3	Negative	
Mike Garton	Dominion Resources, Inc.	5	Negative	
Louis S Slade	Dominion Resources, Inc.	6	Negative	
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.				
Stanley M Jaskot	Entergy Corporation	5	Negative	Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. I n M3 it is unclear what action is intended by the phrase “including the criteria itself”. Since the criteria is specified in R3, it is recommended that the phrase be deleted. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: “Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators.” We also recommend that the wording in R5 be changed to: “Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint.”

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				The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. We also recommend that the High and Severe VSLs that contain the phrase "shall conduct and document" to read "conducted and documented". The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information. The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the 500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events.
Response: Please see our response to your comments in the consideration of comments report.				

Voter	Entity	Segment	Vote	Comment
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	Entities should be required to inform neighbors of the assessment results rather than reaching concurrence. With the approach currently in the standard, an entity could potentially be held responsible for inaction of another planning coordinator. The language should say, "Each Transmission Operator and Balancing Authority shall coordinater load shedding plans among other interconnected entities." Also MidAmerican notes that under frequency event analyses are complex. Therefore, the minimum time frames for anlysis and implementation should be increased to at least 2 years and exception requests for additional time should be allowed.
Response: In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	EOP-003-1 - BC Hydro does not agree with the EOP-003-1 changes. BC Hydro believes that the standard should not be specific to UVLS plans but rather on load shedding plans which may include AUVLS, AUFLS and manual load shedding. If EOP-003 is only for UVLS we don't know how we would be expected to "coordinate" this with other BA's. **Response:** The standard drafting team received several comments on EOP-003 that expressed concern that the removal of under-frequency load shedding in the standard was not clear enough. The standard drafting team made additional modifications to the EOP-003 requirements that clarify that the load shedding referred to in the requirements excludes automatic under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1. PRC-006-1 The frequency performance requirements may vary depending on individual system characteristics. NERC standard on AULS should stay at a high level. The detailed requirements should be left to subgroups to deal with based on their uniqueness and coordinate within their interconnections. - The standards should mainly deal with under-frequency load shedding. The frequency performance on generators should be left to generation interconnection or planning standards. **Response:** The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those

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				generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.
Daniel Brotzman	Commonwealth Edison Co.	1	Negative	EOP-003-1 needs to define the criteria as to when and how UVLS schemes are installed to provide consistency direction to Planning Coordinators and the entities that have to install UVLS schemes. The relationship between the use of UVLS and compliance with TPL-001 standards should be clarified. Is load shedding (including UVLS) allowed to meet the performance criteria in TPL-001? The standard should define when UVLS are applicable to the BES and thus subject to the requirements of EOP-003. UVLS schemes developed for distribution or other purposes beyond criteria should not be discouraged through regulatory burden. UVLS should be carefully defined. Many types of load will cut out on low voltage. **Response:** The standard drafting team received several comments on EOP-003 that expressed concern that the removal of under-frequency load shedding in the standard was not clear enough. The standard drafting team made additional modifications to the EOP-003 requirements that clarify that the load shedding referred to in the requirements exclude automatic under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1. PRC-006-01: The standard lacks guidance as to what the trip settings should be. It is not clear as to how Attachment 1 should be used and doesn't provide specific detail for under frequency set points. Exelon disagrees that R3.3 is easier to understand. Clarification is needed as to where the underfrequency set points are. Do all entities contribute equally to Attachment 1? There needs to be a standardized relationship between GO and TO/DP participation in obtaining the desired level of system performance. There should also be explicit criteria as to what the expectations are for each individual entity. It should be clear that all UFLS entities are to participate equally and that larger entities will not be expected to carry the burden for smaller entities. There should be some recognition in the standard that UFLS schemes currently exist and effort should be made to avoid needlessly changing relays or settings on many thousands of installations if some arbitrary and common set points were to be determined by the PC, thus causing needless expense. It is likely desirable to have slightly different settings for UFLS across a footprint so as to not create load changes that are too abrupt. The current practice of allowing contractual agreements between GOs and DPs for additional load shedding as a voluntary business decision, in the event that a unit owner doesn't comply with the unit trip settings should be addressed. Exelon does not agree with

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				the concept of allowing neighboring Planning Coordinators to define or modify islanding criteria. **Response:** The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters. There should be a single criteria for the determination of an island which is consistent across the interconnection, unless a specific geographic or regional exception is identified. Even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint. **Response:** The proposed standard requires the Planning Coordinators to establish the criteria for selecting islands and does not allow another Planning Coordinator to modify the criteria established in Requirement R1.
Robert Martinko	FirstEnergy Energy Delivery	1	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote for the standard as written. Although we agree that the Planning Coordinator is the appropriate functional entity to develop and implement a UFLS program, we are concerned with the fact that UFLS entities may not know the specifics of their responsibilities until long after this standard is approved. The SDT should consider adjusting the language of the standard to require more transparency and coordination with the UFLS entities during the PC's development of the UFLS program. Also, per the implementation plan, the PC will be given one year to develop its UFLS program. However, the timeframe for the UFLS entity is based on the schedule imposed by the PC. The implementation plan should allow the UFLS entity at least one year (maybe more per capital budget cycles) from the time the PC identifies the UFLS entity in
Kevin Querry	FirstEnergy Solutions	3	Negative	

Voter	Entity	Segment	Vote	Comment
Douglas Hohlbaugh	Ohio Edison Company	4	Negative	their UFLS program. The UFLS entity will need sufficient lead time in those instances that require purchase of new UFLS equipment that will require long term budget planning for implementation. The UFLS entities are identified in the UFLS program established by the PC. However, it is not clear where the PC is explicitly required to notify and coordinate with the UFLS entity. In Requirement R3 it is implied that the PC will notify and coordinate with the UFLS entity per the phrase “including a schedule for implementation by UFLS entities within its footprint”. This requirement needs to be more explicit that the PC will notify the UFLS entity, and the measure for R3 needs to require proof that the PC has done this. We are concerned about the coordination between this UFLS SDT and the GV SDT. It will be difficult to approve and begin implementing the PRC-006-1 standard while the PRC-024-1 standard is still under development and scheduled for approval and implementation at a much later date. For these requirements to be adequately coordinated, the two standards need to be developed, balloted and implemented at the same time. Alternatively, consider adding the following statement in the PRC-006-1 Implementation Plan: "The Effective Date and implementation of this PRC-006-1 standard requires coordination with standard PRC-024-1. Excluding requirement R1, the Effective Date of PRC-006 shall be the later of 1) the completion of the Implementation Plan for PRC-006 or 2) the completion of the Effective Date of the PRC-024-1 standard upon completion of its Implementation Plan."
Kenneth Dresner	FirstEnergy Solutions	5	Negative	**Response:** The SDT added a requirement to the proposed standard, Requirement R14, to ensure that the Planning Coordinators collect and respond to comments submitted by UFLS entities on the UFLS program, including a schedule for implementation and UFLS design assessment.
Mark S Travaglianti	FirstEnergy Solutions	6	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote. Since we do not agree with the standard requirements and have cast a negative vote for the standard, we therefore do not agree with the VSL for the requirements as written.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.				

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James A Ziebarth	Y-W Electric Association, Inc.	4	Negative	From Question 3 on the comment form: Regarding the VSLs for R8, the UFLS entities cannot be punished for failing to meet a schedule if the schedule is not mutually agreed upon between the Planning Coordinator and the UFLS entities to ensure that the UFLS entities are capable of meeting such a schedule. At the very least, there must be some protection for the UFLS entities provided that requires the Planning Coordinator(s) to give the UFLS entities long-term notice of the deadlines that they will need to meet. The lack of any scheduling restrictions for the Planning Coordinators in the standard as written has a strong potential to cause enormous burdens on small UFLS entities that simply do not possess the resources to deal with such data reporting requirements without sufficient advance notice. Additionally, the UFLS entities cannot be penalized for failing to submit data in a format over which they have no control or input. The Planning Coordinator should be required to consult with the UFLS entities and decide upon a mutually agreeable data format in order to ensure that the UFLS entities are capable of providing the required data in the required format. With no language in the standard limiting or clarifying what data can be required of the UFLS entities by the Planning Coordinator, this provision at least should be made to protect small UFLS entities with highly limited resources for dealing with such data reporting requirements. From Question 8 on the comment form: Because Load Serving Entities (not Distribution Providers) are actually responsible for the load in the current Functional Model and Compliance Registry Criteria, they should also be included in the applicability section of this standard. From Question 12 on the comment form: Y-WEA is concerned about this requirement in that it seems to require the installation of facilities rather than just relays. 16 USC 824o (a)(3) gives NERC the authority to regulate existing facilities and planned additions or modifications to those facilities, not to prompt or require modifications or additions to the existing facilities. This proposed requirement seems to run afoul of this section of the USC.
Response: The SDT added a requirement to the proposed standard, Requirement R14, to ensure that the Planning Coordinators collect and respond to comments submitted by UFLS entities on the UFLS program, including a schedule for implementation and UFLS design assessment.				
Kim Warren	Independent Electricity System Operator	2	Negative	Generator owners are not included in the Applicability Section of this standard. We understand from the SDT's responses to the last posting that there is a separate project for generator requirements that would obligate them to provide the required information to the Planning Coordinators with which to design the underfrequency load shedding program. Absent that standard, a Generator Owner has no obligation to provide the necessary data to the Planning Coordinators which can result in the Planning Coordinator failing to meet the PRC-006-1 standard. We therefore request that Generator Owner be included in the Applicability Section and a requirement for it to provide the needed information to the Planning Coordinator be added, or balloting of standard PRC-006-1 be deferred until such a requirement in that other standard is ready for balloting.

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Response: Many commenters indicated that Generator Owners should be included in the applicability of the standard. Some suggested including a data requirement in PRC-006-1 that requires the Generator Owners to submit the necessary data to accomplish Requirement R4; however, the team felt that because such a data requirement already exists in PRC-024 and because the team has clarified in the effective date of the standard that the sub-parts related to generators will not be effective until PRC-024 is approved and effective that adding such a data requirement to PRC-006 would be redundant and possibly cause double jeopardy concerns.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	Instead of reaching concurrence, entities should be just required to inform neighbors of the assessment results. Otherwise entities could potentially be held responsible for inaction of another planning coordinator. The language could be changed to be consistent with the language in EOP-003 R3, such as, "Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected (entities)". MidAmerican notes that past under frequency event analyses are complex and that the minimum time frames for analysis and implementation should be increased to at least 2 years and exception requests for additional time should be allowed.
Response: In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	It is unclear from the Standard that not forming islands in UFLS design is acceptable. Recommend the SDT consider including language to clarify that is not mandatory that system islands by formed in every UFLS design configuration.
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Scott Heidtbrink	Kansas City Power & Light Co.	5	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Response: The proposed standard requires that an island be the basis of UFLS program design – at a minimum Requirement R2 part 2.3 A single island that includes all portions of the BES in either the Regional Entity footprint or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island.				

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Michael Moltane	International Transmission Company Holdings Corp	1	Negative	ITC Holdings strongly suggests that the "planning coordinator" as it relates to UFLS be clearly defined. As written throughout the standard, ITC would be responsible for planning UFLS when we don't own any such systems. Due to the huge impact the definition of "planning coordinator" has on this standard, and the ambiguity that exists with the definition of this entity, ITC must vote negative
Response: An entity that is registered as the Planning Coordinator (or the previous name for the function – Planning Authority), must be prepared to accept responsibility for the requirements assigned to that function. The terms Planning Authority and Planning Coordinator have the same meaning, and are defined in the NERC Glossary of Terms Used in Reliability Standards. The Planning Coordinator does not necessarily own UFLS systems but rather coordinates the planning of such systems among the entities that own, operate and control UFLS.				
Terri F Benoit	Entergy Services, Inc.	6	Negative	NEGATIVE BALLOT WITH REASONS Entergy Ballot PROJECT 2007-01 UNDERFREQUENCY LOAD SHEDDING PROGRAM REQUIREMENTS Ballot Ending July 16, 2010 The following are the reasons associated with our Negative Ballot. Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. In M3 it is unclear what action is intended by the phrase “including the criteria itself”. Since the criteria is specified in R3, it is recommended that the phrase be deleted. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: “Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators.” We also recommend that the wording in R5 be changed to: “Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint.” The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. We also recommend that the High and Severe VSLs that contain the phrase “shall conduct and document” to read “conducted and documented”. The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC

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				change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information. The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the 500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.				
Richard Salgo	Sierra Pacific Power Co.	1	Negative	Negative vote prompted by several concerns: First, the Standards as proposed are a disturbing departure from the present practice of Regional and Interconnection-wide coordination of off-nominal frequency protection. We feel that it must be approached on an Interconnection-wide basis, not as individual Planning Coordinators. The goal should be that the Planning Coordinators develop a coordinated interconnection-wide off-nominal frequency scheme design. This is imperative to ensure adequate UFLS protection across the Interconnection. Secondly, applicability does not appear to include entities who must be responsible to ensure that the UFLS is carried out, for instance, the LSE's and DP's that necessarily must implement the prescribed UFLS protection devices at the distribution level. Finally, we disagree with the concept of frequency-vs-time curves, as this approach will fall short of addressing the unique characteristics of the various NERC Interconnections.
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay				

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within those curves by some margin, e.g., between the two curves of Attachment 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters. Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.				
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	NPCC has already implemented a Region specific UFLS Program incorporating a six year UFLS implementation plan, with year one of the plan having ended June, 2010. As such, Con Edison is concerned with how this version of PRC-006 might impact the NPCC Regional UFLS Standard. Applicability of PRC-006, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved.
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	
Response: The standard drafting team received feedback that many of the existing UFLS programs meet the performance characteristics in the proposed standard. Once this standard is approved the entities with existing programs would need a year to validate their program and validate the schedule for implementation with the UFLS entities. A data requirement already exists in the proposed PRC-024 - the team has clarified in the effective date of the standard that the Parts of the requirement related to generators will not be effective until PRC-024 is approved and effective, that adding such a data requirement to PRC-006 would be redundant and possibly cause double jeopardy concerns.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	oThe proposed measures are vague, not specific and not performance based which leave too much up to the Auditor's interpretation. **Response:** The SDT thinks that the Measures identify the evidence or types of evidence needed to demonstrate compliance with the associated requirement. The SDT thinks that the commenter is proposing that the SDT propose the RSAW not the Measures. oThe proposed standard does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a

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				secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. oThe primary purpose of the UFLS Plan is designed to mitigate the need to form islands by balancing loads and resources. It is a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding event rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not and individual island issue and therefore not driven by an individual PC but by a coordination of PCs effort within the interconnection. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. o The WECC UFLS-DT believes there should be recognized sub-area groups, (consisting of PCs, as assigned by the Reliability Assurer (RA)). These sub-groups would be the agent for the PCs, and would assure the overall coordination within the interconnection. For example, the WECC RA recognizes the following sub-areas for UFLS coordination within the Western Interconnection (WI): Southern Islanding Load Tripping Group, the Northwest Power Pool UFLS group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-groups, PCs could randomly form sub-area groups whose plans may not coordinate on an interconnection wide basis or even address the interconnection reliability needs, but coordinated among the randomly formed sub-groups. The standard, requirements, and measurements should reflect the uniqueness of the individual interconnections and not common, continent wide prescriptions. **Response:** The fourth version of the proposed standard addresses the coordination issue many commenters expressed. Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning

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				Coordinator in the Functional Model Version 5.
Richard J Kafka	Potomac Electric Power Co.	1	Negative	PHI submitted comments
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.				
Francis J. Halpin	Bonneville Power Administration	5	Negative	Please see BPA's comments submitted during the formal comment period ending 7/17/10.
Rebecca Berdahl	Bonneville Power Administration	3	Negative	
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.				
Ralph Frederick Meyer	Empire District Electric Co.	1	Negative	Prefer that a reliability standard requirement should to an entire entity class (per the Functional Model) not some sub-set of that entity. However, if the SDT determines to keep as indicated in this version, then we suggest that section 4 be revised to add clarity. Without the benefit of the background information above, the intent of the language in 4.2 and 4.3 could be lost. We suggest that section 4.2 be revised to read "UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment or automatic switching of Elements as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers" and that 4.3 be deleted.
Response: Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Owner; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding by the Transmission Owner (only). The switching of elements is generally performing at higher voltages than distribution voltages and as a result decided to not include the Distribution Providers in Requirement R10. This is the reason why the SDT did not merge Section 4 parts 4.2 and 4.3.				
Tim Hattaway	PowerSouth Energy Cooperative	5	Negative	R10 needs further clarification. One would assume that the "element" referred to is one that is essential to the correct function of the UFLS scheme?
Response: Commenters expressed that the wording in Requirement R10 "switching of elements" is confusing. The team modified Requirement R10 to clarify that it means: "switching of capacitor banks, Transmission Lines, and reactors" in order to control over voltage as a result of under frequency load shedding.				
Harold Taylor, II	Georgia Transmission Corporation	1	Negative	R3: Recommend diagrams to show the intended difference between 3.3.2 and 3.3.3. 3.3.2 should be "Generating Plants" (NO "/facilites") and 3.3.3 should be "Facilities". This would separate the combustion turbine or combined cycle generation which utilize common bus work from co-generation facilities that tie load and generation to a common utility substation bus.

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				R5: What constitutes concurrence? 100% agreement? Can two or more Planning Coordinators with differing criteria reach a mutual agreement? R10: The use of upper case and lower case letters for emphasis can be confusing. What is the point of capitalizing "Elements"? Is it to imply switching a bulk load center from one island region to another and thus change the balance of generation to load in each island? Is the intent to enable or disable UF tripping for a given load center (substation) as it is transfered from one island region to another?
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters. No changes made. Commenters expressed that the wording in Requirement R10 “switching of elements” is confusing. The team modified Requirement R10 to clarify that it means: “switching of capacitor banks, Transmission Lines, and reactors” in order to control over voltage as a result of under frequency load shedding.				
Douglas E. Hils	Duke Energy Carolina	1	Negative	Requirements R5 and R13 contain the problematic requirement to “reach concurrence”, as discussed in our responses to the comment form. One way to address this concern would be to revise R5 and R13 to require affected Planning Coordinators to share design assessment results and event assessment results and respond to technical questions/comments within a prescribed time period.
Response: Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.				
Tom Bowe	PJM Interconnection, L.L.C.	2	Negative	SDT must define “design assessment”. Is it different from every other one of the other assessments conducted by the PC? Without clarification an RE is left with these questions: Is the requirement to conduct an assessment? Or is it to conduct an assement that sucessfully meets R3? Is the PC non-compliant when its area’s assets can not resolve the studied condition? Additionally, R12 is unclear in what it means by “event actuation”. Is the objective to run an assessment; or is the objective to “design” a solution to islands created during a planning assessment. Clarify meaning of event actuation. R11 can be read to mean “when that event occurred in the real system (i.e. was actuated) then an event analysis must be considered; or it can mean when an assessment shows the creation of an island, then the PC must devise a process or procedure to correct the

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				incident within 1 year. The text is awkward.
Response: The objective of the design assessment is to verify that the design of the UFLS program satisfies R3. For the purposes of PRC-006, the design assessment needs to be distinguished only from the event assessment, which is an after-the-fact analysis of a UFLS event per R11. There are no other assessments required by this standard. It is required to conduct an assessment that shows the UFLS program design satisfies R3 for each of the identified islands from R2. A PC would be non-compliant if its UFLS program cannot satisfy the performance curves in the Attachments up to a 25 percent imbalance between load and generation while considering the sub-points specified in R4. The objective of the event assessment is to analyze events after-the-fact. Event actuation is the time when the event was initiated. The point of R12 is to follow up after an event assessment if the event assessment indicated that the UFLS program did not perform as well as expected, or that improvements may be possible. It is not required that improvements be made, only considered. R11 means "when that event occurred in the real system (i.e. was actuated) then an event analysis must be considered." The PC does not need to "devise a process or procedure to correct the incident within 1 year," though a PC may consider changes to the UFLS program design that might improve its performance in future events of a similar nature in R12.				
Mark Ringhausen	Old Dominion Electric Coop.	4	Negative	See my comments in the VRF/VSL ballot.
Response: Please see our response to your comments in the consideration of comments report.				
Ronald D. Schellberg	Idaho Power Company	1	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. WECC had a disturbance the was negatively impacted by the lack of cordination of UFLS between subregions. Continent wide Frequency-time curves would not account for the interconnection size.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.				
Laurie Williams	Public Service Company of New Mexico	1	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within a Reliability Region as there are Planning Coordinators. Additionally, the proposed standard does not address

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				UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; “For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.				
Richard J. Padilla	Pacific Gas and Electric Company	5	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. The proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. The proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves

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William Mitchell Chamberlain	California Energy Commission	9	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
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George R. Bartlett	Entergy Corporation	1	Negative	The following are the reasons associated with our Negative Ballot. Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. **Response:** Thank you for your support. In M3 it is unclear what action is intended by the phrase “including the criteria itself”. Since the criteria is specified in R3, it is recommended that the phrase be deleted. **Response:** The SDT agrees with the commenter and removed the phrase from both M2 and M3. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: “Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators.” We also recommend that the wording in R5 be changed to: “Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint.” **Response:** The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT’s proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT also made associated changes to the corresponding measures. The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. **Response:** The SDT made conforming changes to the VSL for Requirement R11. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. **Response:** The SDT does not agree with the recommendation to add a range of time to
Joel T Plessinger	Entergy	3	Negative	

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				the VSLs. The SDT established increments in the VSLs according to NERC's VSL guidelines. We also recommend that the High and Severe VSLs that contain the phrase "shall conduct and document" to read "conducted and documented". The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) **Response:** The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." **Response:** The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT also made associated changes to the corresponding measures. We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information. The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the

Voter	Entity	Segment	Vote	Comment
				500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events. **Response:** The responsibility of generator owners resides within a standard under development currently, PRC-024. Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.
John Canavan	NorthWestern Energy	1	Negative	The primary concern identified is that the current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. **Response:** Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; “For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	
John C. Collins	Platte River Power Authority	1	Negative	
Terry L Baker	Platte River Power Authority	3	Negative	
Glen Reeves	Salt River Project	5	Negative	

Voter	Entity	Segment	Vote	Comment
				A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided. **Response:** The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.
Jerome Murray	Oregon Public Utility Commission	9	Negative	The primary concern is that the current proposal does not require coordination within the interconnection. The standard should require the Planning Coordinators (PCs) within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are PCs. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE

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				needs to be included in the Applicability section. **Response:** Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided. **Response:** The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.

Voter	Entity	Segment	Vote	Comment
Chad Bowman	Public Utility District No. 1 of Chelan County	1	Negative	The proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.				
Jerry W Johnson	South Mississippi Electric Power Association	5	Negative	The requirement seems to require the installation of facilities rather than just relays. 16 USC 824o (a)(3) gives NERC the authority to regulate existing facilities and planned additions or modifications to those facilities, not to prompt or require modifications or additions to the existing facilities. Criteria are never actually defined in the requirements. Planning Coordinator footprints are not established. What does “annually maintain” mean? Does it mean the Database requires annual updates, annual reviews or just to provide a database annually? Frequency excursions precede an islanding event. I.e. low frequency initiates UFLS which should prevent an unintentional islanding event. The wording of this requirement makes it seem like the islanding event occurs first and causes the UF. Measures are too vague, lacking specifics, and not performance-based. This would leave too much up to the Auditor’s interpretation. Measures are only valuable if they contain specific targets or specifications that clarify how an entity will be deemed to be compliant with the standard as written. Measures which merely repeat the standard with the inclusion of “shall have evidence such as...” are not very useful. Measures should be explicit, detailed, consistent, and provide useful guidance to entities. These measures do not provide any useful guidance beyond what is specified in the requirement itself. M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that the phrase be deleted. M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. The graphical representation of the

Voter	Entity	Segment	Vote	Comment
				frequency-time curves alone allows plenty of margin for mis-interpretation of the curves data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curves data points The standard lacks guidance as to what the trip settings should be. It is not clear as to how Attachment 1 should be used and doesn't provide specific detail for under frequency set points. Neighboring Planning Coordinators will be making requests and setting criteria for the local planning coordinators and associated UFLS entities. We do not agree with the text "any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating." It is not clear what is included in automatic switching. This requirement is so vague that it does not appear to add anything in addition to the UFLS program design that it is intended to address. It appears that anything that R10 may be designed to address is already covered by R9.
Response: TPL standards require addition of facilities under certain conditions. This standard is not out of line. The SDT disagrees that the jurisdiction of Planning Coordinators and their footprints has not been established. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. Annually maintain means annual updates, though not exclusively. UFLS cannot be expected to mitigate island formation. Most interconnections are large enough that a decline in frequency low enough to cause UFLS operations is highly unlikely unless the interconnection is broken into islands. Most UFLS operations are seen to occur following island formation. The SDT intends to add the performance characteristic curve data points. The under and over frequency performance curves are solely for checking dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points. UFLS entities are not affected, nor will a Planning Coordinator need to make requests of them or set criteria for them as far as island identification is concerned. The SDT believes the quoted text is necessary due to the wide range of island determination criteria (R1) that may be forthcoming. "Automatic switching of Elements" refers to switching of, among other Elements, cap banks to prevent excessive voltages. R10 has been modified to remove the confusion.				
Gregory J Le Grave	Wisconsin Public Service Corp.	3	Negative	The Standard is not ready for implementation because portions of the draft are difficult to interpret due to vague language. R5 and R13 use the phrase "reach concurrence". In addition, it isn't clear if the UFLS entities must have the Planning Coordinator's UFLS program implemented by the standard's effective date.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. UFLS Entities only need to comply with the Planning Coordinator's schedule for application.				

Voter	Entity	Segment	Vote	Comment
Robert D Smith	Arizona Public Service Co.	1	Negative	The standard is too prescriptive. It requires that islands be formed and the underfrequency load shedding be designed to arrest the frequency in the islands and meet several requirements. While this is a valid approach, it is a very restricted and prescriptive approach. The islands formed in the study may not be the islands which actually form when the events happen. The under frequency load shedding scheme should be considered as a safety net and the Planning Coordinator should be given more flexibility. Most of the standard requirements should be guidelines.
Thomas R. Glock	Arizona Public Service Co.	3	Negative	
Mel Jensen	APS	5	Negative	
Dennis Sismaet	Seattle City Light	6	Negative	The standard, requirements, and measurements should reflect the uniqueness of the individual interconnections and not common, continent wide prescriptions.
Response: A continent-wide standard can specify performance curves or it can specify UFLS design parameters; the SDT has opted for performance curves. This is the less restrictive approach of the two. The standard does not require island formation, only identification of islands to be the basis for UFLS assessments. The standard does not require Planning Coordinators to predict islands that may occur in the future; it only requires criteria for island identification in order for the design assessments in R4 to be conducted. UFLS needs to arrest system frequency declines, whether as islands or the interconnection. Guidelines have no place in an enforceable standard. A continent-wide standard must identify requirements that are common to the four interconnections and the SDT believes the standard does that without being unnecessarily prescriptive.				
Michelle Rheault	Manitoba Hydro	1	Negative	This standard is not ready for ballot. See submitted comments.
Mark Aikens	Manitoba Hydro	5	Negative	
Daniel Prowse	Manitoba Hydro	6	Negative	
Response: Please see SDT responses on comment form.				
Jonathan Appelbaum	United Illuminating Co.	1	Negative	UI is voting negative because we believe EOP-003 should apply to manual load shed and uvls. The term load shed is easy to use but can mistakenly be interpreted to inculde automatic underfrequency load shed. Please see our comment form for futher clarifiction
Response: The EOP-003 SAR has very limited scope which allows removal of UFLS from EOP-003 and nothing else. UVLS remains in EOP-003 and another SDT has been assigned to EOP-003. The SDT is making a few other changes to EOP-003.				
James R. Keller	Wisconsin Electric Power Marketing	3	Negative	We agree with the Measures as far as the draft standard is currently written, however, see our comments for questions 11, 12, and 13 that would require modifications to requirements R9 & R10 and to M9 & M10. We agree with the Violation Severity Levels as far as the draft standard is currently written, however, see our comments for questions 11, 12, and 13 that would require modifications to requirements R9 & R10 and the corresponding Violation Severity Levels. Although we agree that the Planning Coordinator has the wide-area view and technical

Voter	Entity	Segment	Vote	Comment
Anthony Jankowski	Wisconsin Energy Corp.	4	Negative	skills to oversee the design of and ensure the effectiveness of a UFLS program, we are concerned with how this concept will actually play out, especially when a UFLS Entity is within multiple Planning Coordinators' footprints. We agree with the expanded scope of the supplemental SAR, however, EOP-003-1 needs further revision to focus this standard solely on manual loadshed. References to the development of both UFLS and UVLS programs need to be removed from EOP-003-1 as PRC-006-1 will cover automatic UFLS programs and a series of other PRC standards already cover automatic UVLS programs. The SDT should delete R2, R4, R7 and M1 from the posted SDT revised draft standard EOP-003-1 as part of supplemental SAR limited scope of revising requirements related to underfrequency loadshedding. In addition, the SDT should give consideration to inserting the word "manual" in front of the words "load shedding" in R3 and R5 in the posted SDT revised draft standard EOP-003-1. The Measures and Violation Severity Level sections would need to be updated accordingly. Although we agree with the intent of the revisions, EOP-003-1 needs further revision to focus this standard solely on manual loadshed.
Linda Horn	Wisconsin Electric Power Co.	5	Negative	References to the development of both UFLS and UVLS programs need to be removed from EOP-003-1 as PRC-006-1 will cover automatic UFLS programs and a series of other PRC standards already cover automatic UVLS programs. The SDT should delete R2, R4, R7 and M1 from the posted SDT revised draft standard EOP-003-1 as part of supplemental SAR limited scope of revising requirements related to underfrequency loadshedding. In addition, the SDT should give consideration to inserting the word "manual" in front of the words "load shedding" in R3 and R5 in the posted SDT revised draft standard EOP-003-1. The Measures and Violation Severity Level sections would need to be updated accordingly. We agree with the concept of using the frequency time performance curves instead of discrete points. However, we would like the SDT to provide additional technical background on the methodology utilized to develop both the underfrequency and overfrequency time performance curves beyond what was discussed in the "Review of Technical Changes to Standard" section in the preface of the "Unofficial Comment Form." We agree with the concept of using the PRC-024 generator underfrequency and overfrequency tripping curves instead of discrete points. In addition, we agree with the generator size and connection threshold clarification. However, we continue to believe that this standard places a burden on the UFLS Entity to shed additional load to make up for generators which do not conform to the PRC-006/PRC-024 curves. For example, if an independent power producer did not conform

Voter	Entity	Segment	Vote	Comment
				with the PRC-006/PRC-024 curves, it places a burden on the UFLS Entity to potentially have to shed additional load, up to the generator's rating, to make up for the non-conforming independent generator. Although we agree with the revision, we disagree with carrying forward the legacy concept of using an entire Regional Entity's footprint as an island. It is highly unlikely that the entire Regional Entity footprint would become an island. What is the technical justification for the continuation of the legacy concept of studying islands consisting of the entire Regional Entity's footprint? In addition, similar to the concurrence that the Planning Coordinators need to reach in R5, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: "The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets." Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R5, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: "The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission." Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Although we agree with the intent of this requirement, similar to the concurrence that the Planning Coordinators need to reach in R5 & R13, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: "The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator

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				footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission." Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R5 & R13, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: "The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets." Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Although we agree with the intent of these requirements, the assessment required in R11 & R13 should only be completed for signif
Response: Please see SDT responses to questions 11, 12 and 13. The EOP-003 SAR has very limited scope which allows removal of UFLS from EOP-003 and nothing else. UVLS remains in EOP-003 and another SDT has been assigned to EOP-003. The SDT is making a few other changes to EOP-003. The over and under frequency versus time performance curves for UFLS were determined to coordinate with the Generator under and over frequency tripping curves (which have been also coordinated with the PRC-024 SDT) and to set a margin between the UFLS and generator curves. That is about all that can be said. The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. Those islands are to be used in UFLS design assessments only, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. (The SDT agrees that there is no technical reason for designating Regional Entity footprints as islands.) The SDT has addressed the matter of GO versus TO/DP obligation for non-conforming generators and has decided that, for the likely small amount of non-conforming generation, that it should be a small burden, if any, to be spread across multiple TO sand DPs. Several other commenters have expressed concern with use of the term "concurrence" and the SDT has modified R5 and R13 to address those concerns by removing "concurrence." The SDT agrees that UFLS Entities should have opportunity to provide input to the Planning Coordinator on what will be required of them. R14 has now been added to the standard and requires a peer review of a Planning Coordinator's design and schedule for implementation by the UFLS Entities. Hopefully, this addresses, at least in part, the commenter's suggestions. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.				
Jason L	Midwest ISO, Inc.	2	Negative	We are voting negative because: 1) EOP-003 is posted in this standards action and was

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Marshall				just balloted last week in the Order 693 directives project. It is not clear how the differences will be resolved. 2) The PC needs frequency characteristics of generators to comply with the standard but the GOs have no obligation to supply them. 3) While conceptually dynamic simulation to test the UFLS schemes is a good idea, it may not be practical. Dynamic simulation of these UFLS schemes involves extreme contingency analysis which stretches the limits of the simulation tools. 4) There is an arbitrary requirement to split islands based on regions.
Response: The EOP-003 conflict has been resolved. PRC-024 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. Dynamic simulations of UFLS performance, including disturbances initiating island formation, have been done in the past and the SDT does not believe they are impractical. There are a number of assumptions that go into UFLS studies, however, and so these studies should be undertaken by experienced planners. The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. Requirement R2, Part R2.3 requires Regional Entity footprints to be identified as islands. Those islands are to be used in UFLS design assessments only, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. (The SDT agrees that there is no technical reason for designating Regional Entity footprints as islands.)				
Janelle Marriott	Tri-State G & T Association Inc.	3	Negative	We believe that individual Planning Coordinators are not the appropriate entities to be responsible for determining criteria for areas that may form islands, for identifying the islands, for developing the UFLS program for periodic assessments, for maintaining databases or for assessing events. The current registration by numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. All Planning Coordinators within an interconnection should be required to collaboratively develop an interconnection-coordinated UFLS Plan. Further, Planning Coordinator footprints are neither defined nor is there any guidance on how they should be established. Every VSL that refers to a PC footprint should be clarified. The primary purpose of any UFLS program should is to mitigate the need to form islands by balancing total system loads and resources. It is only a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding events rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts within the interconnection. We strongly believe that there should be recognized sub-area group(s), which consist of PCs, as assigned by the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA

Voter	Entity	Segment	Vote	Comment
				assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate or address the interconnection reliability needs There is also a concern that EOP-003-2 is currently being balloted based on changes made as a part of the Order 693 Directives. The two versions are not compatible. We believe that “ownership” should be removed from the criteria because it may be different from the operating or controlling entity and both entities cannot be responsible. Load Serving Entities should also be included as a “possible” UFLS entity. Some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. Each interconnection should establish discrete set points based upon stability and dynamic analysis. From discrete set points one can establish criteria which are measurable and performance based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC. Furthermore, the Standard needs to be very explicit that the curves are interconnection performance curves and not specific protective relay set points. The standard should adequately recognize the performance characteristics of different type of generation and a variance should not be required. Faster acting and greater inertia systems should be allowed the operating margins appropriate to their systems. Real differences exist between interconnections. The standard and its performance requirements should reflect this fact. This would allow for the uniqueness of each interconnection to be addressed similar to Hydro Quebec’s variance.

Response: The SDT believes the Planning Coordinator, having a wide-area view and the necessary technical skills, is the proper entity to oversee the design and implementation of UFLS. There is also wide industry support for the Planning Coordinator as the proper entity for UFLS. The Reliability Assurer has a very limited scope of activity in the Functional Model and is not a user, owner or operator of the BES. The SDT recognizes the need to at least preserve coordination on the regional level and has inserted a requirement (Requirement R2, Part 2.3) to identify each Regional Entity footprint as an island to be assessed for UFLS performance. The PC’s within each region will need to work with each other in order to produce a successful assessment.

The SDT disagrees that the jurisdiction of Planning Coordinators and their footprints has not been defined or established. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities.

The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard does not preclude development of Regional UFLS standards and that approach may address WECC’s desire to have one coordinated UFLS design.

The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation, not while a system remains interconnected.

LSEs are not an appropriate entity to implement UFLS because they do not own UFLS relays or switching equipment

The under and over frequency performance curves are solely for checking dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points. Analysis tools do not need to model the performance characteristic curves; the curves are used to check frequency trajectories only. The PC’s UFLS program design must comply with these curves in simulated response so performance is not at the PC’s

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discretion. A continent-wide standard can specify performance curves or it can specify UFLS design parameters; the SDT has opted for performance curves. This is the less restrictive approach of the two.				
Kathleen Goodman	ISO New England, Inc.	2	Negative	We believe that the applicability section, which states: UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers Excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This appears to be a missing link that needs to be addressed before the standard can be approved. Also, the standard is potentially in conflict with the work to be done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. This would present yet another example of lack of coordination on NERC Standards development.
Response: PRC-024 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. The SDT has coordinated with the PRC-024 SDT so that both PRC-006 and PRC-024 are using the same under and over frequency generator tripping curves. Note that the situation of data required by another standard exists elsewhere; for example, TPL standards compliance requires data from MOD standards.				
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Negative	We disagree with the inclusion of the curves at the end of the standard - Attachment 1. The curves may not be realistic depending on the topology of the BES in any particular area.
Response: The SDT acknowledges that UFLS programs shedding more than 25-30 percent of load may need to apply different UFLS performance characteristic curves, but these curves are realistic up to at least 25 percent of load. The SDT does not believe topology to be a relevant factor, except that topology may lead to the need to arm larger amounts of UFLS.				
Paul Rocha	CenterPoint Energy	1	Negative	With regards to the proposed PRC-006-1; CenterPoint Energy is concerned about the overly prescriptive nature of this proposal and cannot support it in its present form. In particular, a requirement to identify areas that “may Island” might, arguably, make sense for a large interconnection such as the eastern or western interconnect, but it makes no sense for a smaller interconnect such as ERCOT that, essentially, is already an island for the purposes of this standard. Even for the larger interconnections, there are limitless possibilities of potential “islands” that could occur given certain combinations of contingencies. Since it is impractical to identify every conceivable island, it is unclear what level of diligence and documentation would be required to demonstrate to an auditor’s satisfaction that the responsible entity has reasonably identified areas that “may” island. This ambiguity and subjectivity is contrary to objective number 2 in the Project Background to develop a standard “with clearly defined requirements and unambiguous language”.

Voter	Entity	Segment	Vote	Comment
Response: All that is required concerning island identification (R1, R2) is to devise some criteria considering historical events and system studies and use those criteria to identify some islands. This does not mean that every conceivable island must be identified. The criteria can be as simple or elaborate as a Planning Coordinator desires. The SDT does not believe this is overly prescriptive, nor does it believe that it is ambiguous. However, island identification is admittedly subjective and it is difficult to offer more specific guidance in the standard without limiting adaptability.				
Michael Ibold	Xcel Energy, Inc.	3	Negative	Xcel Energy believes that the standard still contains many issues that are not clear and need to be resolved. Among these issues is the mapping of PC to subordinate entities in areas where a regional entity or RTO has not taken on the PC role. Also, there are concerns around how small generators (less than the threshold specified) are addressed. Detailed comments were submitted to NERC with the concurrent comment period.
Response: Please see SDT response to these comments on the comment form. The SDT disagrees that the mapping of Planning Coordinators to subordinate entities is a significant issue. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. This standard does not apply to Generator Owners, but this SDT has coordinated on the development of PRC-024 with that SDT. Although this has long been a subject of debate, the SDT generally believes that generators smaller than the Statement of Compliance Registry thresholds can be omitted without significantly compromising reliability. GOs below the threshold could be registered if necessary for reliability according to the Compliance Registry Criteria.				
Liam Noailles	Xcel Energy, Inc.	5	Negative	Xcel Energy believes that the standard still contains many issues that are not clear and need to resolved. Among these issues is the mapping of PC to subordinate entities in areas where a regional entity or RTO has not taken on the PC role. Also, there are concerns around how small generators (less than the threshold specified) are addressed. Detailed comments were submitted to NERC with the concurrent comment period.
David F. Lemmons	Xcel Energy, Inc.	6	Negative	
Response: Please see SDT response to these comments on the comment form. The SDT disagrees that the mapping of Planning Coordinators to subordinate entities is a significant issue. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. This standard does not apply to Generator Owners, but this SDT has coordinated on the development of PRC-024 with that SDT. Although this has long been a subject of debate, the SDT generally believes that generators smaller than the Statement of Compliance Registry thresholds can be omitted without significantly compromising reliability. GOs below the threshold could be registered if necessary for reliability according to the Compliance Registry Criteria.				
Gregory L Pieper	Xcel Energy, Inc.	1	Negative	Xcel Energy believes the standard still contains many aspects that are not clearly understood by entities, including what is needed to demonstrate a compliant PSMP. Comments have been submitted concurrently to NERC via the draft comment response form.
Response: Please see SDT response to these comments on the comment form.				
Edward P. Cox	AEP Marketing	6	Affirmative	AEP has provided some general comments to the last posting.

Voter	Entity	Segment	Vote	Comment
Response: Please see SDT response to these comments on the comment form.				
David H. Boguslawski	Northeast Utilities	1	Affirmative	Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved. Also, the standard is potentially in conflict with the work being done on the Generator Verification Standard, which proposes to have Generator Performance during Frequency and Voltage Excursions contained in PRC-024. Sufficient coordination on NERC Standards development needs to occur on a going forward basis.
Response: PRC-024 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. The SDT has coordinated with the PRC-024 SDT so that both PRC-006 and PRC-024 are using the same under and over frequency generator tripping curves. Note that the situation of data required by another standard exists elsewhere; for example, TPL standards compliance requires data from MOD standards.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved. This standard seems to be contrary to FERC's stated concern with NPCC(Oct. 2009 Washington DC meeting) to develop a standard that can support the program it was designed to enforce.....the applicability as stated in the standard and by NERC registry criteria restricts and excludes the need for GO's that may in aggregate be necessary for a reliable UFLS program, to adhere to the standard. The standard also is potentially in conflict with the work being done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. Sufficient coordination on NERC Standards development needs to occur on a going forward basis.
Response: PRC-024 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. The SDT has coordinated with the PRC-024 SDT so that both PRC-006 and PRC-024 are using the same under and over frequency generator tripping curves. Note that the situation of data required by another standard exists elsewhere; for example, TPL standards compliance requires data from MOD standards.				
Saurabh Saksena	National Grid	1	Affirmative	At present, the proposed implementation plan language describes a one year phase-in period for compliance that is intended to provide the Planning Coordinators with

Voter	Entity	Segment	Vote	Comment
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Affirmative	sufficient time to (i) develop and/or modify UFLS programs; and, (ii) to establish an implementation plan for all required equipment changes. It must be recognized that any implementation plan would probably cover a multi-year period reflecting the time required to perform the engineering, purchasing, installation, and testing phases associated with implementing new and/or modified UFLS schemes. As an example, NPCC has already implemented a Region specific UFLS Program incorporating a six year UFLS implementation plan, with year one of the plan having ended June, 2010. As such, NPCC is concerned with how the final language included in the NERC UFLS implementation plan might impact the NPCC-specific UFLS Implementation Program. NPCC will closely monitor NERC's efforts in developing its UFLS Reliability Standard so NPCC can appropriately include the continued implementation of its Region specific UFLS Program within the NPCC Regional Standard PRC-006-NPCC-1, the required Regional Entity companion standard to the NERC UFLS Standard.
Response: The SDT believes that NPCC's six-year implementation plan will not be adversely affected by this standard or this standard's implementation plan.				
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Affirmative	Constellation Power Generation is voting affirmative in this ballot, however, there are still some issues with this project. Primarily, R10 appears to provide BWRs with some relief regarding compliance with the more restrictive UF trip setpoints; however, R7 and R8 are still applicable to them too. I think an auditor could look at R7 and R8 in isolation and say that BWRs may be in violation of those requirements. A potential fix may be to add the following text to R7 and R8 - "[S]ubject to the exceptions and provisions set forth in R10, ..." Another concern is that the title for Figure 1 lists R8, yet the figure applies to R7, R8, R9, and R10. Constellation Power Generation suggests adding the other relevant requirement #s.
Response: The SDT suspects the commenter's comments apply to a different standard.				
Thomas W. Richards	Fort Pierce Utilities Authority	4	Affirmative	Please consider clarifying R10. It's a bit unclear wheather this is pertaining to the switching of capacitor banks to prevent an overvoltage condition.
Response: Yes, "automatic switching of Elements" refers to switching of, among other Elements, cap banks. R10 has been modified to remove the confusion.				

Voter	Entity	Segment	Vote	Comment
Charles H Yeung	Southwest Power Pool	2	Affirmative	SPP votes in favor of the standard but directs the SDT to the ISO RTO Council comments submitted on the PRC-006 standards. We are concerned the generator owner/operators are not included as applicabile registered entities to this standard but understand there is a separate effort to develop generator owner/operator standards that could require them to provide UFLS data to Planning Coordinators. Absent that enforceable requirement, PCs could be subject to inappropriate violations if a GO fails to provide needed UFLS data. In order to move new standards forward that rely on other yet to be approved standards, NERC must take a sensible approach in enforcement of requirements if a violation is found to be caused by gaps in enforceable standards as mentioned.
Response: PRC-024 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006.				
Steven Grego	MEAG Power	3	Affirmative	The reference to "automatic switching of Elements" needs to be clarified. Does it mean that the TO needs to switch capacitor banks, or does it refer to the breakers equipped with UF relays? If it is referring to capacitor banks, is this applicable near major generation busses?
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Affirmative	
Response: Yes, “automatic switching of Elements” refers to switching of, among other Elements, cap banks. R10 has been modified to remove the confusion.				
Larry E Watt	Lakeland Electric	1	Affirmative	This standard requires regional (collaborative) effort, however; it does not assign regional responsibility.
Response: Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES. The SDT believes that, and the industry widely supports, the Planning Coordinator is the best entity.				
Jeff Nelson	Springfield Utility Board	3	Abstain	SUB provided some responses on the Comment Form.
Response: See SDT responses on comment form.				

Consideration of Comments on Second Ballot — Project 2007-01 Underfrequency Load Shedding
Date of Ballot: 07/24/10 - 08/03/10

Summary Consideration:

- Comments received during the second ballot expressed confusion over the actual application of the curves in the Attachment to the standard. Several commenters indicated that the graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves' data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curve data points. The SDT agrees and has modified the curves to better clarify what is intended. The SDT added break-points and combined the curves (Attachment 1 and 2 into one curve now in Attachment 1). The curves are solely for checking the frequency trajectories of simulations and not for setting UFLS relays.

- Several commenters expressed concern that the Applicability section of the standard, as proposed, excludes generators; however, R4 requires PCs to model generator specific information. The suggestion to include the Generator Owners in the proposed standard will be problematic because Generator Owner data requirements already exist in the PRC-024-1 draft and are expected to remain. The SDT has clarified in the effective date of PRC-006 that the sub-parts related to modeling of generator trip settings will not be effective until PRC-024 is approved and effective. Adding a Generator Owner data requirement to PRC-006 would be redundant and cause double jeopardy concerns. It is the case that some standards are dependent on data requirements found in other standards. An example is that data necessary to comply with TPL standards is required under MOD standards.

- Many entities located in the Western Interconnection expressed concern that there is still a fundamental problem with the standard in that it does not specifically require the Planning Coordinators (PC) within an Interconnection to coordinate their plans amongst themselves. The SDT has worked with WECC to develop a proposed Variance to the continent-wide standard applicable to the Western Interconnection entities that addresses these concerns.

- The SDT made minor conforming changes to EOP-003-2 as requested by some commenters to clarify that the standard excludes automatic under-frequency load shedding.

Several commenters pointed out that the terminology of "other affected Planning Coordinators" (R5 & R13) is unqualified and vague. The Planning Coordinator qualification should be completely clear and unambiguous and proposed changing the applicable text in R5 from "other affected Planning Coordinators" to "other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island". (Similar language was adopted for R13.) The SDT agrees with the commenters and modified Requirements R5 and R13 by clarifying that the other Planning Coordinators are those: "whose areas or portions of whose areas are also part of the same identified island".

- Many commenters opposed the addition of Requirement R14 requiring the Planning Coordinators to respond to written comments on their program, design and data submittal. The comments indicated that this requirement either does not go far enough to secure involvement of the DPs and TOs or is procedural in nature and should not be included in a reliability standard. The SDT added this requirement between the initial and the second ballot to address concerns expressed that the DPs and TOs should have a voice in the development of the program and

implementation schedule. The SDT agrees that the DPs and TOs should have a voice in the process but in general, Planning Coordinators should be coordinating with entities in their area in fulfilling their Functional Model roles. The SDT thinks that a response to comments is about as much as a standard can require. Requirements for entities to be involved with each other and work together causes one entity's compliance to be dependent on another's. This has generally been viewed as unacceptable by the industry. This standard does not preclude development of regional standards in order to provide opportunity for all interested entities in the region to be involved.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	(1) PRC-006, R1 should be modified such that PC is required to coordinate development of the islanding criteria in consultation with TP and DP. Further, presently the RE is involved in performing or coordinating the islanding/UFLS studies. We believe that RE should continue to be involved. (2)The SDT has added R14 for PC to respond to written comments on their program, design and data submittal. Responding is not the same as involving and working with the TP and DP initially in development of the progarm, design, and data needs. We believe that PC should consult and coordinate appropriate TP and DP in development of these items. (3)EOP-003-1, R2, the last phrase should be modified from "...load shedding scheme is required." to "...load shedding scheme is necessary to minimize the risk of uncontrolled failure of the interconnected system to match the "Purpose" of the standard.
Response: (1) In general, Planning Coordinators should be coordinating with entities in their area in fulfilling their Functional Model roles. A peer review could be established for the R1 island identification criteria similar to R14, but the SDT is reluctant to add another requirement without wider industry comment. Requirements cannot be made enforceable to entities such as the RE that are not users, owners or operators of the BES under the Compliance Monitoring and Enforcement Program. (2) A response to comments is about as much as a standard can require. Requirement for entities to be involved with each other and work together causes one entity's compliance to be dependent on another's. This has generally been viewed as unacceptable by the industry. This standard does not preclude development of regional standards in order to provide opportunity for all interested entities in the region to be involved. (3) The scope of this drafting team's EOP-003 SAR is limited to removing automatic UFLS from EOP-003-1. This does not include making any			

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
changes to R2.				
Henry Delk, Jr.	SCE&G	1	Negative	1) SCE&G proposes an effective date of 24 months after regulatory approval. We believe the currently proposed effective date of 12 months after regulatory approval would not allow enough time to ensure compliance due to the requirements to establish criteria to identify islands, coordinate results with other Planning Coordinators, and reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion. A number of these requirements cannot be met until a prior requirement is completed and each of these requirements requires coordination with other utilities which will increase the amount of time necessary to obtain compliance. As a result, SCE&G believes an effective date of 24 months after regulatory approval would be much more practical and desirable than the currently proposed 12 month effective date. 2) The graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curves data points.
Matt H Bullard	South Carolina Electric & Gas Co.	6	Negative	
Response: 1. The standard drafting team received feedback that many of the existing UFLS programs meet the performance characteristics in the proposed standard. Once this standard is approved the entities with existing programs would need a year to validate their program and validate the schedule for implementation with the UFLS entities. 2. The SDT agrees and has modified the curves to better clarify what is intended.				
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	1. Assigning the program design to the Planning Coordinator - in all honesty, this should be assigned to the Region. However, with the demise of the RRO, the RA not being available to us to assign things to, and FERC saying that we cannot assign things to the same entity that audits us (i.e., the RE), we had no real choice but to drop down one level to the PCs. 2. No LSE Applicability - this is inconsistent with FRCC's PRC-006 which assigns the amount of load to be shed to the LSE. However, the rest of the country is adamantly against assigning it to LSEs (especially in RTOs where some LSEs do not own distribution equipment at all). Hence, the DP is the preferred applicable entity to have the relays themselves. TOs are there to address historical arrangements primarily in the Midwest and West where TOs provide UFLS for DPs through grandfathered, often

Voter	Entity	Segment	Vote	Comment
				verbal, arrangements. We will still be able to aggregate smaller entities load into an FMPA-wide value for full-requirements members of FMPA through joint registration as a DP (e.g., FMPA would register as a DP to meet some of the requirements of the new PRC-006 with an associated revision to our Compliance Contract) 3. Note that there are significantly more modeling efforts than we may have done in the past; however, other regions' experience is that the increased modeling is important. 4. R10 is a little confusing, but has to do with the need to switch transmission level capacitors out of service during a UFLS event to prevent over-voltages. 5. In general, the standard is almost impossible to meet without a regional effort (e.g., 2.3). The Drafting Team struggled with this because the region is the "right" place to assignt eh program, but, we could not assign it there, so, the standard was written to sort of "force" regional cooperative efforts. In general, it should not be all that difficult to meet the requirements of the standard through FRCC efforts.
Response: 1. Thank you for understanding the difficulties with applicability. 2. Thank you for understanding the SDT position on LSE applicability. 3. The SDT agrees that modeling is a significant factor with this standard. 4. Thank you for understanding the need for R10. 5. The SDT does not think it would be impossible to comply without a regional effort, but a regional effort is certainly desirable. Thank you for understanding the SDT's approach to try to preserve the regional efforts.				
Dan R. Schoenecker	Midwest Reliability Organization	10	Negative	1. No VRFs should be "High" for a program of last resort. 2. Don't agree with R14 & R13. R13, wording "coordinate" not easy to prove for compliance. Coordinate doesn't have a valid compliance methodology since entities could be found non-compliant for actions or inaction beyond their control. The NSRS proposes wording "shall provide". 3. In R3 & R5 the wording "affected" needs better definition, the NSRS suggests rewording the affected paragraph to provide a more "bright line" criteria such that they reference PCs that share a common island to be the affected PCs. 4. R14 is procedural and not appropriate for a reliability standard. 5. Several issues need to be addressed in previously submitted comments. 6. This standard is too complicated. It could be simplified to the following requirements; it should require a documented Planning Coordinator (PC) UFLS plan, data is provided to the PC, PC should determine design

Voter	Entity	Segment	Vote	Comment
				characteristics, and verify through simulation that the plan works as designed. 7. For R2.3 & R4, each PC can't study an entire Region or Interconnection; they don't have the resources and data. Resulting studies maybe duplicative and contain conflicts in assumptions and results. 8. For R11, should not be for just any UFLS events (e.g., small local area events with few or no generators in the island), but should include all disturbance events as defined in EOP-004 that should be studied.
Response: 1. The SDT disagrees because of the importance of a last line of defense. The drafting team has posted its justification for assignment of VRFs – the justification identifies how the High VRF meets both NERC and FERC guidelines for setting VRFs. 2. "Coordination" is defined by the sub-parts of R13 (which has since been modified for further clarification). 3. The standard has been modified to address this concern. The word, "affected" is not used in the revised standard. The text in R5 was changed from "other affected Planning Coordinators" to "other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island". (Similar language was adopted for R13.) 4. Peer review procedures such as R14 are used elsewhere in approved NERC standards, specifically FAC-010 and FAC-011. The procedure has industry support. It allows Transmission Owners and Distribution Providers to at least have some say in what they will be obligated to implement. 5. Please see responses to those comments. 6. The SDT disagrees that this standard is too complicated. The requirements are necessary for reliability of UFLS programs. The commenter's suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, there would be no coordination required between adjacent Planning Coordinators, no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays. 7. The SDT agrees that each PC studying the region or interconnection is undesirable, but cannot require that they work together without setting up a condition where one entity's compliance is subject to what other entities do. If a Planning Coordinator does not wish to study the region on its own, that Planning Coordinator can try to work with the other Planning Coordinators. R7 requires sharing of UFLS data between Planning Coordinators. It is true that studies may be duplicative, but that could be avoided by Planning Coordinators working together. Conflicts should be resolved after fulfilling R5 and R13 though that is not required here. 8. The scope of the commenter's suggestion goes beyond what is necessary for UFLS purposes.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	1. Several issues still need to be addressed in previously submitted comments. 2. This standard is too complicated and should be simplified to the following requirements; a documented Planning Coordinator (PC) UFLS

Voter	Entity	Segment	Vote	Comment
				plan, data provided to the PC, the PC should determine minimum design characteristics, entities should verify through simulation that the plan works as designed, and entities should provide their plan to adjacent interconnected NERC registered entities as evidence of coordination. 3. The performance curves the attachments should clearly state what approximately expected loss of life is being imposed on generator owners / operators to meet the curve expectations. Is the Generator under frequency trip model curve expecting a 5% or 10% loss of life probability per under frequency event for each unit? Generator Owners / Operators need to understand what kind of risk a standard imposes to make decisions on how best to comply with NERC standards, even if that decision is simply whether to change unit settings to meet a proposed curve or not. Past comments. Instead of reaching concurrence, entities should be just required to inform neighbors of the assessment results. Otherwise entities could potentially be held responsible for inaction of another planning coordinator. The language could be changed to be consistent with the language in EOP-003 R3, such as, "Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected (entities)". MidAmerican notes that past under frequency event analyses are complex and that the minimum time frames for analysis and implementation should be increased to at least 2 years and exception requests for additional time should be allowed.
Response: 1. Please see responses to previous comments. Requirements to reach concurrence have been removed. The SDT does not believe that UFLS events in general will take more than a year to analyze. The SDT agrees that requests for extensions should be permitted, but requiring that of NERC cannot be written into a standard. Wide-spread and complicated events will probably end up being analyzed by NERC anyway. 2. The SDT disagrees that this standard is too complicated. The requirements are necessary for reliability of UFLS programs. The commenter's suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, coordination between adjacent Planning Coordinators cannot be achieved by simply exchanging information, there would be no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays. 3. This is a subject for Project 2007-09 and the PRC-024-1 SDT. This standard is not applicable to Generator Owners. Loss of life depends on both the specifics of events and the specific characteristics of individual generators; the question is not one that can be answered with any certainty.				

Voter	Entity	Segment	Vote	Comment
Jason Shaver	American Transmission Company, LLC	1	Negative	Although Draft 4 of Project 2007 addressed some of our issues that we identified with Draft 3, there are still the following outstanding concerns. Comments on Draft 3 of PRC-006-1: 1. The NERC Compliance Registry Criteria (Revision 5.0, Sections II.b and III.b.2) clearly states that any Transmission Owner with end-use load connected to their facilities must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. Change Applicability items 4.2 and 4.3 to simply "Transmission Owners" and "Distribution Providers", respectively without future qualification. Change the accountable entity in Requirements R8 and R9 from "UFLS entity" to "Distribution Provider". 2. Requirements (R3, R4, R9, & R10) associated with UFLS programs (which are non-primary system preservation measures) should have a lower risk factor that primary preservation measures. Reduce the "High" VRF levels to at least "Medium". 3. If a Planning Coordinator's area includes only a small portion of a Regional Entity area or an Interconnection area, then it should not have to identify the entire Regional Entity area or the entire Interconnection area as a basis for its UFLS program design (R2.3) and conduct a UFLS design assessment for those islands (R4). Remove Requirement R2.3. 4. The underfrequency design performance curve (R3.1, Attachment 1) may be appropriate for 25% UFLS programs and has an arbitrary cutoff at 60 seconds. This performance curve is not appropriate for 30%, 40%, or 50% UFLS programs, such as those that are presently in the MRO and may be fitting for the MRO or other Regions in the future. Add curves that are appropriate for at least 30%, 40%, and 50% UFLS programs to Attachment 1 or note that the curve only applies to Planning Coordinators that have UFLS programs that are not beyond 25%. 5. The overfrequency design performance curve (R3.2, Attachment 2) may be appropriate for 25% UFLS programs and has an arbitrary cutoff at 60 seconds. This performance curve is not appropriate for 30%, 40%, or 50% UFLS programs, such as those that are presently in the MRO and may be fitting for the MRO or other Regions in the future. Add curves that are appropriate for at least 30%, 40%, and 50% UFLS programs to Attachment 2 or note that the curve only applies to Planning Coordinators that have UFLS programs that are not beyond 25%. 6. The terminology of "other affected Planning Coordinators" (R5 & R13) is

Voter	Entity	Segment	Vote	Comment
				unqualified and vague, which will lead to entity and regulator interpretation problems. The Planning Coordinator qualification should be completely clear and unambiguous. Change the applicable text from "other affected Planning Coordinators" to "other Planning Coordinators in the same island". 7. The scope of Requirement R10 should not be restricted to only Transmission Owners. Distribution Providers might be able to provide automatic switching of reactive power elements that are more effective and appropriate than Transmission Owner elements. Replace "Transmission Owner" with "UFLS entity. 8. Compliance with requirements that use the term, "coordinate", are subject to wide interpretation and problematic to document. In R13, change the wording from "coordinate with other affected Planning Coordinators on the event assessment" to "provide its event assessment to other Planning Coordinators in the subject island". 9. The new R13.1 requirement (conduct a UFLS event assessment) is duplicative of R11 (conduct an assessment of a BES islanding event) [double jeopardy]. Remove Requirement R13.1. 10. A requirement (R13.2) that calls for the identification and reporting of differences between the UFLS event assessments of Planning Coordinators that evaluate the same event is inappropriate for a Reliability Standard. Other Planning Coordinators, Regional Entities, and the ERO can review the various event assessment reports and draw their own conclusions, if the assessments are provided to them. Remove R13.2 and include wording in R13, "provide its event assessment to other Planning Coordinators and Regional Entities in the subject island, as well as the ERO." 11. A requirement (R14) that calls for written responses to comments from UFLS entities regarding proposed UFLS program changes is inappropriate for a Reliability Standard. If a UFLS entity asks for an explanation from its Planning coordinator of the reasons for proposed UFLS program changes and is ignored, then they can take their grievance to the applicable Regional Entity, the ERO, or the courts. They do not need a Reliability Standard requirement to resolve the issue. Remove Requirement R14. Comments for EOP-003-1: 1. The revised wording for Requirements R3 and R5 unintentionally excludes manual underfrequency load shedding. Change the related text from "excluding under-frequency load shedding" to "excluding automatic under-frequency load shedding".

Voter	Entity	Segment	Vote	Comment
Response: 1. In some regions, Transmission Owners that do not have end-use load connected to them are the implementers of UFLS; the standard needs to accommodate that practice. 2. UFLS can be a last line of defense against catastrophic events; the SDT believes these VRFs are appropriate to that role. The drafting team has posted its justification for assignment of VRFs – the justification identifies how the High VRF meets both NERC and FERC guidelines for setting VRFs. 3. The SDT believes it desirable to preserve regional coordination of UFLS and R2.3 exists to help further that goal. Planning Coordinators could and should work together to avoid duplication, though that cannot be required. If this sub-requirement were to be removed, there would be no explicit mechanism for regional coordination of UFLS. 4&5. The attachment to R3 applies to load-generation imbalances of up to 25 percent. While it may be more difficult for programs with a higher percent capability to satisfy these criteria, the SDT believes this is achievable. Coordination with generator tripping is still necessary and the same generator curves (coordinated with PRC-024-1) would apply unless a regional variance is proposed. 6. The standard has been modified to address this concern. The word, "affected" is not used in the revised standard. The text in R5 was changed from "other affected Planning Coordinators" to "other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island". (Similar language was adopted for R13.) 7. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Owner; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding by the Transmission Owner (only). The switching of elements is generally performing at higher voltages than distribution voltages and as a result decided to not include the Distribution Providers in Requirement R10.8. Exchange of event assessments between Planning Coordinators is implied. The sub-parts of R13 in the revised standard specify what is meant by "coordinate." 9. The previous R13.1 has been removed to address this point (also R5.1). 10. The SDT disagrees; a first step in resolving differences is to identify those differences. The desire is for differences to be resolved somehow before compliance audits, though resolution cannot be required. An alternative is for Planning Coordinators to work together on one event assessment, though that cannot be required either. 11. The SDT believes R14 is appropriate to give Transmission Owners and Distribution Providers opportunity to comment BEFORE a UFLS program is finalized and they become subject to compliance to provide the specified load tripping. The term "automatic" has been added to EOP-003 R3 and R5 per the commenter's suggestion.				
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	Although the latest revision is improved over the previous one, especially in terms of added clarity in some areas, there is still a fundamental problem in that it does not specifically require the Planning Coordinators (PC) within an Interconnection to coordinate their plans amongst themselves. The current version of the standard would allow for all of the PCs within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are PCs. The standard still

Voter	Entity	Segment	Vote	Comment
				references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. PG&E believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection. The draft standard is also very prescriptive is some cases, going as far as specifying maximum Volts per Hertz limits in simulated studies of islanded scenarios, as well as frequency versus time envelopes or boundaries that specify acceptable over/under frequency excursions. These types of performance limits should be specified at the Interconnection level based on the characteristics of the Interconnection, not at the Continent-wide level.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Thomas R. Glock	Arizona Public Service Co.	3	Negative	Although the SDT has made changes in trying to define the Protection System the definition remains too prescriptive. In particular, the devices providing current and voltage inputs as well as the dc supply. These items are also used for other functions not related to the reliability of the BES. They are critical to business and operation of the generating systems and not solely dedicated to protective relaying. Including them in the definition obligates the utility to methods where there should be some discretion.
Response: This comment does not seem to relate to this standard, PRC-006.				

Voter	Entity	Segment	Vote	Comment
Linda R. Jacobson	City of Farmington	3	Negative	Another concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The curves are solely for checking the frequency trajectories of simulations and not for setting UFLS relays. The Quebec interconnection has a variance. Since the standard was last balloted, WECC has proposed an Interconnection-wide variance to the requirements in this standard, but the variance does not propose different curves. The Planning Coordinators do have the responsibility to determine UFLS design parameters including frequency set points. The SDT decided in the first draft that these parameters should not be determined in a continent-wide standard for the very reason that regions and interconnections have unique characteristics. This is decidedly not a least common denominator approach. The SDT disagrees that the performance characteristic curve approach is reverse engineering, but rather designing to a target. The reliability justification for the curves is their coordination with generator tripping.				
Gregory Campoli	New York Independent System Operator	2	Negative	Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved. This standard seems to be contrary to FERC's stated concern (Oct. 2009 Washington DC meeting) to develop a standard that can support the program it was designed to enforce.....the applicability as stated in the standard and by NERC registry criteria restricts and excludes the need for GO's that may in aggregate be necessary for a reliable UFLS program, to adhere to the standard. The standard also is potentially in conflict with the work being done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. Sufficient coordination on NERC Standards development needs to occur on a going forward basis.
Response: The suggestion to include the Generator Owners in the proposed standard will be problematic because Generator Owner data requirement already exist in the PRC-024-1 draft and are expected to remain. The SDT has clarified in the effective date of PRC-006 that the sub-parts related to modeling of generator trip settings will not be effective until PRC-024 is approved and effective. Adding a Generator Owner				

Voter	Entity	Segment	Vote	Comment
data requirement to PRC-006 would be redundant and cause double jeopardy concerns. It is the case that some standards are dependent on data requirements found in other standards. An example is that data necessary to comply with TPL standards is required under MOD standards.				
Claudiu Cadar	GDS Associates, Inc.	1	Negative	Applicability. 4.2. The wording in the standard may need to reformulate to read "[...] established by the Planning Coordinators within the Regional Entity's footprint.[...]". Applicability. 4.3. While SDT response indicates that 4.3 is intended for TOs that may need to switch equipment other than load, however we consider that 4.3 is a redundant assignment since reference to TOs controlling UFLS equipment already included in 4.2.2. Effective Date. 5. Depending on when this standard becomes mandatory and enforceable, it may fall between entities' budgeting periods. An 18 months implementation would allow for all entities to budget the funds necessary to implement the standard. Requirements. R1. While the SDT response to one of RBB member states that R1 and R2 are meant to only "devise some criteria considering historical events and system studies and use those criteria to identify some islands" understanding that "this not mean that every conceivable island must be identified", we consider that both R1 and R2 requirements should be reworded to reflect this intended approach. While the SDT has added requirement R14 with regards to the collection and response to comments on the UFLS program, schedule for implementation and collection of data, there is no requirement to state how the PC will address comments (if any) from the participating entities on the suggested criteria. We find appropriate to include an interpretation to standard requirements. We also noted that the SDT proposed a "Medium" VRF and we consider that since the requirement is not meant to draw specific lines, the VRF should be set back to "Lower" as originally proposed. Requirements. R8. How the UFLS entity suppose to provide data to the Planning Coordinator and when is suppose to do that? The newly added requirement R14 regarding the collection and response to comments on the UFLS program, schedule for implementation and collection of data does not establishes the time limits and how the UFLS entity is to provide data to the PC. This requirement leaves all these at the PC discretion without any specific timelines, or process sequencing which both the PC and the UFLS entity should follow.

Voter	Entity	Segment	Vote	Comment
				Requirements. R9, R10. What if the UFLS entity does not agree with Planning Coordinator's assessment? See comment on R8; requirement R14 does not respond to this question.
Response: The phrase "…within the Regional Entities footprint" is unnecessary since it is the Planning Coordinator's footprint that rules UFLS implementation. Applicability 4.3 is specifically for Transmission Owners that may need to switch Elements other than load or UFLS equipment, and in fact may not even have load connected to their facilities or UFLS equipment. R1 and R2 are in fact worded to reflect the SDT's intended approach. The schedule for implementation by UFLS entities is determined by the Planning Coordinators, not the Implementation Plan or the standard. Planning Coordinators will need to address any R14 comments before finalizing their UFLS program and schedule, which puts a time limit on their responses in view of the timeline imposed by the Implementation Plan. R14 VRF is already "Low." (Now changed to "Lower.") The schedule and format for UFLS Entities to supply data to the Planning Coordinator is based on the schedule and format devised by the Planning Coordinator, subject to their response to R14 comments. That is all the standard can require. A standard cannot require entities to agree with each other.				
Clement Ma	BC Hydro and Power Authority	5	Negative	BCHPA concurs with WECC comments as follows: The primary concern identified in the first position paper is that the proposal does not require coordination within individual interconnections. The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. WECC believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be necessary to meet the continent-wide

Voter	Entity	Segment	Vote	Comment
				performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	Comments associated with the negative vote are contained in the Project 2007-01 comment form submitted by TVA
Response: Please see SDT responses in that comment form.				
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	comments provided on comment form
Response: Please see SDT responses in that comment form.				
Robert W. Roddy	Dairyland Power Coop.	1	Negative	concerned that generation limits are too conservative.
Response: Not sure if this comment means too conservative from a generator's perspective or from the transmission reliability perspective. The SDT believes, in coordination with the 2007-09 project team, that an acceptable balance has been achieved between competing interests.				
Edward F. Groce	Avista Corp.	5	Negative	Coordination of UFLS plans should be required in the standard.
Response: Coordination of UFLS plans is achieved by (1) common performance criteria in R3, (2) coordination between Planning Coordinators within a region or interconnection per R2.3 and R5, and (3) coordination per R5 within any other identified islands that span multiple Planning Coordinator areas.				
Paul Morland	Colorado Springs Utilities	1	Negative	CSU offers the following comments: R3 (Attachments) It is not clear how attachment 1 should be used. Are the curves performance curves? Set point curves? R10 Need more clarity on what is meant by "Automatic Switching of Elements"? Does it mean a TO needs to automatically switch capacitor banks to avoid overvoltages?
Response: Attachment 1 curves are performance criteria consisting of boundaries for frequency trajectories in simulations run to assess UFLS performance. The SDT added break-points and combined the curves (Attachment 1 and 2 into one curve now in Attachment 1). The curves are solely for checking the frequency trajectories of simulations and not for setting UFLS relays. Yes, "automatic switching of Elements" refers to switching of, among other Elements, cap banks. R10 has been modified to remove the confusion.				

Voter	Entity	Segment	Vote	Comment
Michael F Gildea	Dominion Resources Services	3	Negative	Currently there is no requirement for Generator Owners to provide trip settings for non-conforming units to the Planning Coordinator. Absent such a requirement, the responsibility for compliance would be placed on the Transmission Owner. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. So, we suggest the addition of a requirement (applicable to the Generator Owner) to provide the information (as needed in R3-R3.3.3) to the Planning Coordinator. Approving this standard without addressing these comments will not achieve the reliability objective of the FERC Order 693 directive and ultimately will result in a standard that cannot be implemented as written.
Mike Garton	Dominion Resources, Inc.	5	Negative	
Response: PRC-006 and PRC-024 are coordinated and the generator curves and tables match. The SDT recognizes that PRC-024 may be approved at a different time and has inserted a provision in the implementation plan document to account for that possibility. Generator applicability is deferred to PRC-024 to avoid double jeopardy. The number of non-conforming generators is expected to be small and should not cause a compliance issue for Planning Coordinators in an interim period, if any, before Generator Owner data becomes available to them.				
Stanley M Jaskot	Entergy Corporation	5	Negative	Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. In M3 it is unclear what action is intended by the phrase “including the criteria itself”. Since the criteria is specified in R3, it is recommended that the phrase be deleted. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: “Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators.” We also recommend that the wording in R5 be changed to: “Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by that Planning Coordinator which include a portion of its footprint along

Voter	Entity	Segment	Vote	Comment
				with portions of another PC(s) footprint." The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. We also recommend that the High and Severe VSLs that contain the phrase "shall conduct and document" to read "conducted and documented". The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information.

Voter	Entity	Segment	Vote	Comment
				The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the 500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events.

Response: The SDT agrees and has modified M3 to remove the phrase "including the criteria itself".

The SDT has modified R5 and M5 to reflect the intent that only UFLS programs within the PC areas that are a part of the island under study need to work in conjunction to meet the performance requirement in R3.

The SDT also modified R5 and M5 to remove the "concurrence" requirement and provide a means by which each PC can meet this requirement alone or by working with other PCs.

The SDT has modified the VSLs for R11 to make these corrections.

R4 – consideration of timeliness - The SDT considered this and decided that the program reassessment is a binary task which automatically makes this a severe violation if not completed within the 5 year timeframe.

The SDT has modified R13 to eliminate any duplication between R13 and R11.

R14 requires the UFLS entities be notified of a comment period and for the PCs to respond to those comments prior to a UFLS program becoming effective. Requirement R3 has been modified to specifically indicate that the UFLS program must include "**notification** of and a schedule for implementation" in support of your suggestion.

The SDT modified the implementation plan to state, "Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1." Per the implementation plan, the requirement to model data from the GOs is not mandatory until after the GOs are required to provide the data by PRC-024. This is similar to the requirement to model the BES by the TPL standards, while the requirement by entities to provide the data used to model the BES is contained in the MOD standards.

The existing standard PRC-009, which this standard is intended to replace, currently requires that an assessment be performed for all events regardless of size. The SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the requirement the same or better than what exists today.

Voter	Entity	Segment	Vote	Comment
Daniel Brotzman	Commonwealth Edison Co.	1	Negative	EOP-003-1 needs to define the criteria as to when and how UVLS schemes are installed to provide consistency direction to Planning Coordinators and the entities that have to install UVLS schemes. The relationship between the use of UVLS and compliance with TPL-001 standards should be clarified. Is load shedding (including UVLS) allowed to meet the performance criteria in TPL-001? The standard should define when UVLS are applicable to the BES and thus subject to the requirements of EOP-003. UVLS schemes developed for distribution or other purposes beyond criteria should not be discouraged through regulatory burden. UVLS should be carefully defined. Many types of load will cut out on low voltage. PRC-006-01: The standard lacks guidance as to what the trip settings should be. It is not clear as to how Attachment 1 should be used and doesn't provide specific detail for under frequency set points. Exelon disagrees that R3.3 is easier to understand. Clarification is needed as to where the underfrequency set points are. Do all entities contribute equally to Attachment 1? There needs to be a standardized relationship between GO and TO/DP participation in obtaining the desired level of system performance. There should also be explicit criteria as to what the expectations are for each individual entity. It should be clear that all UFLS entities are to participate equally and that larger entities will not be expected to carry the burden for smaller entities. There should be some recognition in the standard that UFLS schemes currently exist and effort should be made to avoid needlessly changing relays or settings on many thousands of installations if some arbitrary and common set points were to be determined by the PC, thus causing needless expense. It is likely desirable to have slightly different settings for UFLS across a footprint so as to not create load changes that are too abrupt. The current practice of allowing contractual agreements between GOs and DPs for additional load shedding as a voluntary business decision, in the event that a unit owner doesn't comply with the unit trip settings should be addressed. Exelon does not agree with the concept of allowing neighboring Planning Coordinators to define or modify islanding criteria. There should be a single criteria for the determination of an island which is consistent across

Voter	Entity	Segment	Vote	Comment
				the interconnection, unless a specific geographic or regional exception is identified. Even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint.
Response: Another drafting team is being assigned EOP-003. The scope of the UFLS drafting team is restricted by the SAR to removing automatic UFLS from EOP-003 only. The under and over frequency performance curves in Attachment 1 are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misconstrued as applying to UFLS relay set points. Many of the issues the commenter raises are going to need to be dealt with by the Planning Coordinators. It would be very difficult and probably not in the interest of BES reliability for these issues to be resolved in this standard. R3.3 is based on IEEE guidelines for setting V/Hz protection. The Planning Coordinator, as part of the UFLS program design, will need to determine the participation level of the variously sized Transmission Owners and Distribution Providers. The SDT fully expects that existing UFLS programs will be sufficient to comply with the performance characteristic curves and Planning Coordinators will not need to arbitrarily re-determine UFLS design parameters. The SDT has addressed the matter of GO versus TO/DP obligation for non-conforming generators and has decided that, for the likely small amount of non-conforming generation, that it should be a small burden, if any, to be spread across multiple TOs and DPs. Neighboring Planning Coordinators cannot redefine or modify another Planning Coordinator's R1 island determination criteria. A Planning Coordinator may, however, select an island that overlaps a neighboring Planning Coordinator's footprint in complying with R2. A single criterion for island determination is not something that can be put into a continent-wide standard because there are likely to be many acceptable approaches to these criteria.				
Robert Martinko	FirstEnergy Energy Delivery	1	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote. We feel that the new R14 puts an administrative compliance burden on the PC because it requires a response to all written comments. Furthermore, R14 does not address subsequent changes to the UFLS program and more importantly fails to address FE's underlying concern that the standard still gives full authority to the PC to set an implementation schedule for a UFLS Entity.
Kenneth Dresner	FirstEnergy Solutions	5	Negative	
Mark S Travaglianti	FirstEnergy Solutions	6	Negative	

Voter	Entity	Segment	Vote	Comment
Douglas Hohlbaugh	Ohio Edison Company	4	Negative	We believe that PRC-006-1 should specifically allow the UFLS entity at least 12 months to comply with the PC's UFLS program upon being notified of new obligations. Please see our suggested revision to R14 at the end of these ballot comments. In Requirement R3 it is implied that the PC will notify and coordinate with the UFLS entity per the phrase "including a schedule for implementation by UFLS entities within its footprint", and in Requirement R14 it is also implied. However, there should be an explicit requirement in this standard (either in R3 or R14) for the PC to notify the UFLS entity of their obligations per the PC's UFLS program. As a minor note, in the initial ballot we stated that we noticed that EOP-003-1 is the current version approved by FERC. The revised version per this project should therefore be EOP-003-2. Based on the concerns we have stated above, we suggest a revision to R14 as follows: "R14. Each Planning Coordinator shall meet the following during the development of the UFLS program and during subsequent revisions of the program that require additional UFLS equipment installations by the UFLS entity [VRF: Low][Time Horizon: Long-Term Planning]: 14.1. Submit an initial draft of its UFLS program for review and feedback by the identified UFLS Entity before the UFLS program is finalized. 14.2. Assure that the schedule for implementation affords the UFLS entity at least 12 months to achieve compliance."
Response: R14 establishes a peer review process, but cannot go further due to the need to have clear assignments of responsibility. A regional standard could be drafted to gain the participation of other entities. The SDT does not believe that a written response to comments is burdensome. EOP-003-1 should be EOP-003-2 and this has been fixed. The SDT believes that the implied requirements for Planning Coordinators to notify UFLS Entities are sufficient, and that Planning Coordinators, in fulfilling their role as coordinators, will not impose unreasonable demands on UFLS Entities. Requirement R3 has been modified to specifically indicate that the UFLS program must include "**notification** of and a schedule for implementation" in support of your suggestion.				
Kevin Querry	FirstEnergy Solutions	3	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote for the standard as written. Although we agree that the Planning Coordinator is the appropriate functional entity to develop and implement a UFLS program, we are concerned with the fact that UFLS entities may not know the specifics of their responsibilities until long after this standard is approved. The SDT should consider adjusting the language of the standard to require more

Voter	Entity	Segment	Vote	Comment
				transparency and coordination with the UFLS entities during the PC's development of the UFLS program. Also, per the implementation plan, the PC will be given one year to develop its UFLS program. However, the timeframe for the UFLS entity is based on the schedule imposed by the PC. The implementation plan should allow the UFLS entity at least one year (maybe more per capital budget cycles) from the time the PC identifies the UFLS entity in their UFLS program. The UFLS entity will need sufficient lead time in those instances that require purchase of new UFLS equipment that will require long term budget planning for implementation. The UFLS entities are identified in the UFLS program established by the PC. However, it is not clear where the PC is explicitly required to notify and coordinate with the UFLS entity. In Requirement R3 it is implied that the PC will notify and coordinate with the UFLS entity per the phrase "including a schedule for implementation by UFLS entities within its footprint". This requirement needs to be more explicit that the PC will notify the UFLS entity, and the measure for R3 needs to require proof that the PC has done this. We are concerned about the coordination between this UFLS SDT and the GV SDT. It will be difficult to approve and begin implementing the PRC-006-1 standard while the PRC-024-1 standard is still under development and scheduled for approval and implementation at a much later date. For these requirements to be adequately coordinated, the two standards need to be developed, balloted and implemented at the same time. Alternatively, consider adding the following statement in the PRC-006-1 Implementation Plan: "The Effective Date and implementation of this PRC-006-1 standard requires coordination with standard PRC-024-1. Excluding requirement R1, the Effective Date of PRC-006 shall be the later of 1) the completion of the Implementation Plan for PRC-006 or 2) the completion of the Effective Date of the PRC-024-1 standard upon completion of its Implementation Plan."
Response: R14 establishes a peer review, but cannot go further due to the need to have clear assignments of responsibility for compliance. Requiring entities to coordinate with each other or work together causes one entity's compliance to be dependent on another's. This has generally been viewed as unacceptable by the industry. A regional standard could be drafted to gain the participation of other entities in the UFLS program and implementation schedule. In general, Planning Coordinators should be coordinating with entities in their area in fulfilling their Functional Model roles. Requirement R3 and Measure M3 were both modified to include "notification" as suggested. The SDT recognizes that PRC-024 may be approved at a different time and has inserted a provision in the implementation plan document to				

Voter	Entity	Segment	Vote	Comment
account for that possibility. The number of non-conforming generators is expected to be small and should not cause a compliance issue for Planning Coordinators in an interim period, if any, before Generator Owner data becomes available to them. The aspects of coordination between PRC-006 and PRC-024 are a small subset of the content of each standard and do not warrant delaying implementation of one standard until the other is approved.				
James A Ziebarth	Y-W Electric Association, Inc.	4	Negative	From Question 3 on the comment form: Regarding the VSLs for R8, the UFLS entities cannot be punished for failing to meet a schedule if the schedule is not mutually agreed upon between the Planning Coordinator and the UFLS entities to ensure that the UFLS entities are capable of meeting such a schedule. At the very least, there must be some protection for the UFLS entities provided that requires the Planning Coordinator(s) to give the UFLS entities long-term notice of the deadlines that they will need to meet. The lack of any scheduling restrictions for the Planning Coordinators in the standard as written has a strong potential to cause enormous burdens on small UFLS entities that simply do not possess the resources to deal with such data reporting requirements without sufficient advance notice. Additionally, the UFLS entities cannot be penalized for failing to submit data in a format over which they have no control or input. The Planning Coordinator should be required to consult with the UFLS entities and decide upon a mutually agreeable data format in order to ensure that the UFLS entities are capable of providing the required data in the required format. With no language in the standard limiting or clarifying what data can be required of the UFLS entities by the Planning Coordinator, this provision at least should be made to protect small UFLS entities with highly limited resources for dealing with such data reporting requirements. From Question 8 on the comment form: Because Load Serving Entities (not Distribution Providers) are actually responsible for the load in the current Functional Model and Compliance Registry Criteria, they should also be included in the applicability section of this standard. From Question 12 on the comment form: Y-WEA is concerned about this requirement in that it seems to require the installation of facilities rather than just relays. 16 USC 824o (a)(3) gives NERC the authority to regulate existing facilities and planned additions or modifications to those facilities, not to prompt or require modifications or additions to the existing facilities. This proposed requirement seems to run afoul of this section of the USC.
Response: PCs should work with UFLS entities on schedule for data reporting. Requirement R14 is designed to facilitate communication between these entities. Ultimately, the PC is required to perform the design assessments which it cannot do without the necessary modeling data. The				

Voter	Entity	Segment	Vote	Comment
schedule and format for UFLS Entities to supply data to the Planning Coordinator is based on the schedule and format devised by the Planning Coordinator, subject to their response to R14 comments. That is all the standard can require. A standard cannot require entities to agree with each other. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. The SDT is not sure where this concern is coming from. If the comment is referring to Requirement R10, it does not require the installation of any equipment other than relays to facilitate the "automatic switching of capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding".				
Jeff Mead	City of Grand Island	5	Negative	I echo MRO NSRS comments.
Response: Please see SDT response to MRO comments.				
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Negative	It is apparent that this UFLS Standard is very complex and wish to thank the SDT in their efforts so far. A UFLS system is in place as a last line of defense in arresting frequency when operator actions cannot keep up with a rapid decline in frequency. There are many other step that are to be taken prior to automatic UFLS action. With that being said, there are several areas that still need to be reviewed. The word "coordinate" (R13) should be replaced with "shall provide" since proving compliance within different regions will be met with different views. The "High" VRFs make this another priority. As stated in the FERC Technical Conference on July 6, 2010, everything cannot be a priority. Do not see how R14 supports the reliability of the BES, it is purely procedural. Do not think that a PC has the capability to do a design assessment (R4) based on R2.3 for "or the Interconnection in which the PC's area resides. Since there are many (special) attributes that apply to different PC areas, this Standard could be boiled down to 1) Require a documented PC UFLS plan, 2) Data prescribed by the PC shall be forwarded to the PC from entities within their area that own or operate UFLS devices, 3) PC's should determine design characteristics based on the area's physical capabilities and limitations, 4) Verify through simulation that the plan works as designed, 5) PC's shall provide their plans to other physically connected PC areas. This would allow each PC with determining system characteristics unique to their system.

Voter	Entity	Segment	Vote	Comment
Response: In R13, the sub-parts define what is meant by "coordinate." The sub-parts are specific enough that there should not be a problem with differing interpretations. UFLS can be a last line of defense against catastrophic events; the SDT believes these VRFs are appropriate to that role. The drafting team has posted its justification for assignment of VRFs – the justification identifies how the High VRF meets both NERC and FERC guidelines for setting VRFs. Peer review procedures such as R14 are used elsewhere in approved NERC standards, specifically FAC-010 and FAC-011. The procedure has industry support. It allows Transmission Owners and Distribution Providers to at least have some say in what they will be obligated to implement. In R2.3, the island can be either the region or interconnection; it does not have to be the interconnection. The commenter's suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, coordination between adjacent Planning Coordinators cannot be achieved by simply exchanging information, there would be no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays.				
Hugh A. Owen	Public Utility District No. 1 of Chelan County	6	Negative	It is import tha6t there be single coordinated plan for the WECC. It appears this proposed standard as worded, would allow for the possibility of as many different UFLS plans within an interconnec as there are planning coordinators without a mandate that they be coordinated.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	It is unclear from the Standard that not forming islands in UFLS design is acceptable. Recommend the SDT consider including language to clarify that is not mandatory that system islands by formed in every UFLS design configuration.
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Scott Heidtbrink	Kansas City Power & Light Co.	5	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Response: A Planning Coordinator must identify at least one island to be used as the basis for the R4 UFLS design assessment. However, this does not mean that islands must be identified from a Planning Coordinator's R1 criteria. As a minimum, the region or interconnection in which a Planning Coordinator's area is located must be identified as an island per R2.3.				

Voter	Entity	Segment	Vote	Comment
Louise McCarren	Western Electricity Coordinating Council	10	Negative	Main concern is that this proposal still doesn't require an interconection-wide coordinated plan. While the current version of the standard would allow for all of the Planning Coordinators within an interconnection to agree upon and implement a single coordinated plan, it does not require a single coordinated plan. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. WECC believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Terri F Benoit	Entergy Services, Inc.	6	Negative	NEGATIVE BALLOT WITH REASONS Entergy Ballot PROJECT 2007-01 UNDERFREQUENCY LOAD SHEDDING PROGRAM REQUIREMENTS Ballot Ending July 16, 2010 The following are the reasons associated with our Negative Ballot. Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. In M3 it is unclear what action is intended by the phrase “including the criteria itself”. Since the criteria is specified in R3, it is recommended that the phrase be deleted. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: “Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators.” We also recommend that the wording in R5 be changed to: “Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by

Voter	Entity	Segment	Vote	Comment
				that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint." The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. We also recommend that the High and Severe VSLs that contain the phrase "shall conduct and document" to read "conducted and documented". The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required

Voter	Entity	Segment	Vote	Comment
				information. The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the 500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events.

Response: The SDT agrees and has modified M3 to remove the phrase "including the criteria itself".

The SDT has modified R5 and M5 to reflect the intent that only UFLS programs within the PC areas that are a part of the island under study need to work in conjunction to meet the performance requirement in R3. The SDT also modified R5 and M5 to remove the "concurrence" requirement and provide a means by which each PC can meet this requirement alone or by working with other PCs.

The SDT has modified the VSLs for R11 to make these corrections.

The SDT considered this and decided that the program reassessment is a binary task which automatically makes this a severe violation if not completed within the 5 year timeframe.

The SDT has modified R13 to eliminate any duplication between R13 and R11.

Requirement R3 has been modified to specifically indicate that the UFLS program must include "**notification** of and a schedule for implementation" in support of your suggestion.

The SDT has added R14 which now requires the UFLS entities be notified of a comment period and for the PCs to respond to those comments prior to a UFLS program becoming effective.

The SDT modified the implementation plan to state, "Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1." Per the implementation plan, the requirement to model data from the GOs is not mandatory until after the GOs are required to provide the data by PRC-024. This is similar to the requirement to model the BES by the TPL standards, while the requirement by entities to provide the data used to model the BES is contained in the MOD standards.

The existing standard PRC-009, which this standard is intended to replace, currently requires that an assessment be performed for all events regardless of size. The SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the requirement the same or better than what exists today.

Voter	Entity	Segment	Vote	Comment
Richard Salgo	Sierra Pacific Power Co.	1	Negative	Negative vote prompted by several concerns: First, the Standards as proposed are a disturbing departure from the present practice of Regional and Interconnection-wide coordination of off-nominal frequency protection. We feel that it must be approached on an Interconnection-wide basis, not as individual Planning Coordinators. The goal should be that the Planning Coordinators develop a coordinated interconnection-wide off-nominal frequency scheme design. This is imperative to ensure adequate UFLS protection across the Interconnection. Secondly, applicability does not appear to include entities who must be responsible to ensure that the UFLS is carried out, for instance, the LSE's and DP's that necessarily must implement the prescribed UFLS protection devices at the distribution level. Finally, we disagree with the concept of frequency-vs-time curves, as this approach will fall short of addressing the unique characteristics of the various NERC Interconnections.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	oThe proposed measures are vague, not specific and not performance based which leave too much up to the Auditor's interpretation. oThe proposed standard does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. oThe primary purpose of the UFLS Plan is designed to mitigate the need to form islands by balancing loads and resources. It is a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding event rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not and individual island issue and therefore not driven by an individual PC but by a coordination of PCs effort within the interconnection. o The WECC UFLS-DT believes there should be recognized sub-area groups, (consisting of PCs, as assigned by the Reliability Assurer (RA)). These sub-groups would be the agent for the PCs, and would assure the overall coordination within the interconnection. For example, the WECC RA recognizes the following sub-areas for UFLS coordination within the Western Interconnection (WI): Southern Islanding Load Tripping Group,

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				the Northwest Power Pool UFLS group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-groups, PCs could randomly form sub-area groups whose plans may not coordinate on an interconnection wide basis or even address the interconnection reliability needs, but coordinated among the randomly formed sub-groups. The standard, requirements, and measurements should reflect the uniqueness of the individual interconnections and not common, continent wide prescriptions.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Francis J. Halpin	Bonneville Power Administration	5	Negative	Please see BPA's comments submitted during the formal comment period ending 7/17/10.
Rebecca Berdahl	Bonneville Power Administration	3	Negative	
Response: Please see the SDTs response to your comments submitted during the formal comment period ending 7/17/10.				
Jim D. Cyrulewski	JDRJC Associates	8	Negative	PRC-006 remains overly complicated especially Requirement 14.
Response: R14 establishes a peer review. It is not overly complicated.				
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	PRC-006-1 implicitly allows incompatible UFLS programs to exist within the same synchronous interconnection. Each PC is not only allowed, but is required to design and implement its own UFLS programs. A requirement does exist in PRC-006-1 that the UFLS programs be “coordinated” among “all other affected Planning Coordinators.” Nevertheless, “coordinated” is a vague term and can simply mean “notified”. How coordination is measured

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Janelle Marriott	Tri-State G & T Association Inc.	3	Negative	and enforced is also questionable. Allowing multiple UFLS schemes to exist in the same interconnection, with no oversight as to how well they interact is a haphazard approach. UFLS programs that are not developed interconnection-wide can, among other things, result in excessive load shedding and corresponding frequency oscillations that degrade into cascading outages. PRC-006-0 requires the Regional Entity to "develop, coordinate, and document a UFLS program." This top-down approach makes a more congruous interconnection-wide program more likely. Further, since PRC-007-0 requires UFLS owners to comply with the Regional Entity's programs, individual conflicting UFLS schemes among UFLS Entities are also less probable. As currently written, PRC-006-1 specifically removes both the oversight and scheme consistency the previous standards provided. This makes conflicting programs more likely. This degrades, not improves Bulk Electric System Reliability. The NERC Functional Model defines the Reliability Assurer as the entity that "...coordinates activities of functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer area and adjacent areas." With regard to UFLS, the coordination of functional entities is absolutely necessary to secure the reliability of the BES. This coordination function belongs to and is best handled by the Reliability Assurer. More specific comments on the draft standard follow, but the fundamental thesis of the current draft, which moves UFLS design responsibility down from the RA to the PC, should be changed. The responsibilities to design, coordinate, and analyze a UFLS program within an interconnection should remain with the RA. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. A. Introduction 1.-3. No comment. 4.1. should be changed from Planning Coordinators to Reliability Assurers. 4.2. Planning Coordinators should be changed to Reliability Assurers.

Voter	Entity	Segment	Vote	Comment
				4.3. is redundant to 4.2.1. and should be removed. **Response**: The SDT thinks there is confusion over having Transmission Owners as part of UFLS Entities but separated out as Transmission Owners in Requirement R10.. The team reviewed the rationale for this structure. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Owner; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding by the Transmission Owner (only). The switching of elements is generally performing at higher voltages than distribution voltages and as a result decided to not include the Distribution Providers in Requirement R10. 5. No comment. B. Requirements R1. Reliability Assurers rather than individual Planning Coordinators need to develop and document the potential for island formation. However, this requirement may not contribute to the reliability of the BES and could be removed. R2. Reliability Assurers rather than individual Planning Coordinators are the best entities to determine how islands should be formed. The current registration by numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. R2.3. seems to require each Planning Coordinator to ultimately divide into multiple islands or separate its transmission system from all other transmission systems as its own island. The purpose of the UFLS program should be to mitigate the need to form islands by balancing total system loads and resources. It is only a secondary function to balance the loads and resources after the islands have been formed. Recommend eliminating R2 unless the Reliability Assurer becomes the functional entity responsible for the UFLS program development. **Response**: The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because

Voter	Entity	Segment	Vote	Comment
				most UFLS operations are seen to occur following island formation. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. R3. Underfrequency events are not local events that individual systems experience unless islands have already formed. The total interconnected system ratio of generation to load needs to be evaluated to determine at what frequencies the loads must be tripped and restored. Performance of this function by individual Planning Coordinators is a duplication of effort and will still require the entities to concur with interconnected/affected Planning Coordinators (see R5.). We recommend that the functional entity that develops the UFLS program be changed from Planning Coordinator to Reliability Assurer. R3.1. and R3.2. We recommend combining Attachment 1 and Attachment 2 into a single graph, making frequency the abscissa, and requiring simulations to maintain frequencies inside the resulting envelope. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. The SDT added break-points and combined the curves (Attachment 1 and 2 into one curve now in Attachment 1). The curves are solely for checking the frequency trajectories of simulations and not for setting UFLS relays. R3.3. Volts/Hertz (V/Hz) protection should be based upon transformer and generator protection requirements It is possible that V/Hz generator

Voter	Entity	Segment	Vote	Comment
				protection schemes exist that are more sensitive than 1.10 p.u. and 1.18 p.u.. The bases for the 1.18 p.u. and 1.1 p.u. values are not evident and may not be technically supportable when compared against actual protection settings or allowable post-contingency voltage bands. Compliance with these performance characteristics does not guarantee the generators will stay online during UF events. Recommend removing R3.3.1, R3.3.2, and R3.3.3 and replacing R3.3 with: "Generator and generator step-up transformer V/Hz protection elements shall not be violated." **Response**: The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT believes there is a need for V/Hz requirements because shedding load will cause voltages to climb, which may cause excitation systems / voltage regulators to reach the end of their range, which can lead to a V/Hz condition that could cause generators to trip through GSU protection or other similar protection systems. Therefore, the SDT believes that V/Hz of 1.18 p.u for 2 seconds, etc., can be reached at significantly higher frequencies than 57.2 Hz. The standard does not require modeling of V/Hz protection and only requires monitoring of voltage and frequency and designing the UFLS program to meet the performance criteria described in 3.2. The V/Hz values are based on Threshold values from IEEE C37.102 (Guide for AC Generator Protection) and C37.106 (Guide for Abnormal Frequency Protection for Power Generating Plants), and C37.91 (Guide for Protective Relay Applications to Power Transformers). R4. The Reliability Assurer should be the entity that conducts and documents the periodic UFLS program periodic design assessment. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a

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				set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. R5. This requirement is a good example of why the UFLS should be developed by the Reliability Assurer and not individual Planning Coordinators, since each must coordinate with all the other affected Planning Coordinators. “Coordinate” can be as simple as communication between parties (see PRC-001-1 R5) or can be detailed technical study performance and mutual agreements (see PRC-001-1 R3 and M1). If the Reliability Assurer has an approved UFLS program then the UFLS entities will need to comply with the program and the vague “coordination” issue no longer exists. R6. Change Planning Coordinator to Reliability Assurer. Entity. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. R7. Change to “Each Reliability Assurer shall provide its UFLS database containing data necessary to model its UFLS program to other Reliability Assurers within its Interconnection within 30 days of a request. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.

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				R8. Replace every instance of Planning Coordinator with Reliability Assurer. Requiring UFLS entities to provide UFLS scheme data is proper; however, this requirement may duplicate R1.4 in MOD-13-1. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. R9. And R10. Since a Transmission Owner is a UFLS Entity, these requirements are redundant. Recommend combining R9. and R10 and ending the new requirement with "as appropriate." Also, the UFLS program should have been developed by the Reliability Assurer rather than the Planning Coordinator. **Response**: Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements. The team modified Requirement R10 to clarify that it means: "switching of capacitor banks, Transmission Lines, and reactors" to control over voltage as a result of under frequency load shedding. R11. Change Planning Coordinator to Reliability Assurer. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.

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				R12. Change Planning Coordinator to Reliability Assurer. R13. Change Planning Coordinator to Reliability Assurer. R14. Change Planning Coordinator to Reliability Assurer. Recommend developing a requirement for the Reliability Assurer to provide a comment period within the time frames established in their bylaws. C. Measures - Our comments to the Measures are comparable to the comments on the Requirements with regard to entities involved. Where requirements are suggested in the comments to be removed, the accompanying measure needs to be removed. D. Compliance 1.1 - Add NERC to monitor Reliability Assurer compliance. 1.2 - Change Planning Coordinator to Reliability Assurer in all instances. Requirements that we propose removing would be removed from data retention requirements. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. Violation Severity Levels (VSLs) The VSL references to Planning Coordinator should be changed to Reliability Assurer. VSLs for Requirements previously recommended for removal can be removed. R11. What violation does the “Lower VSL” indicate? R12. What is the true significance behind going from Moderate VSL to Severe VSL in a matter of two months when there is a two year period for the design assessment? R14. The UFLS program developer should respond to all comments before UFLS program implementation. Recommend High VSL if i **Response**: The drafting team has posted its justification for assignment of VSLs – the justification identifies how the VSLs meet the NERC and FERC guidelines for setting VSLs.
Response: A regional variance for the WECC interconnection has been included which should also address several of these concerns.				

Voter	Entity	Segment	Vote	Comment
Ralph Frederick Meyer	Empire District Electric Co.	1	Negative	Prefer that a reliability standard requirement should to an entire entity class (per the Functional Model) not some sub-set of that entity. However, if the SDT determines to keep as indicated in this version, then we suggest that section 4 be revised to add clarity. Without the benefit of the background information above, the intent of the language in 4.2 and 4.3 could be lost. We suggest that section 4.2 be revised to read "UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment or automatic switching of Elements as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers" and that 4.3 be deleted.
Response: Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Owner; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding by the Transmission Owner (only). The switching of elements is generally performing at higher voltages than distribution voltages and as a result decided to not include the Distribution Providers in Requirement R10.				
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Negative	R14 is procedural and not appropriate for a reliability standard R11 should not be for just any UFLS events (e.g., small local area events with few or no generators in the island), but should include all disturbance events as defined in EOP-004 that should be studied. This standard is too complicated. It could be simplified to the following requirements; it should require a documented Planning Coordinator (PC) UFLS plan, data should be provided to the PC, PC should determine design characteristics, and verify through simulation that the plan works as designed.
Response: Peer review procedures such as R14 are used elsewhere in approved NERC standards, specifically FAC-010 and FAC-011. The procedure has industry support. It allows Transmission Owners and Distribution Providers to at least have some say in what they will be obligated to implement. The scope of the commenter's suggestion on R11 goes beyond what is necessary for UFLS purposes. The SDT disagrees that this standard is too complicated. The requirements are necessary for reliability of UFLS programs. The commenter's overall suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, there would be no coordination between adjacent Planning Coordinators, no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays.				

Voter	Entity	Segment	Vote	Comment
Douglas E. Hils	Duke Energy Carolina	1	Negative	Requirements R5 and R13 contain the problematic requirement to "reach concurrence", as discussed in our responses to the comment form. One way to address this concern would be to revise R5 and R13 to require affected Planning Coordinators to share design assessment results and event assessment results and respond to technical questions/comments within a prescribed time period.
Response: The SDT has modified R5 and R13 to reflect the intent that only UFLS programs within the PC areas that are a part of the island under study need to work in conjunction to meet the performance requirement in R3. The SDT also modified R5 and R13 to remove the "concurrence" requirement and provide a means by which each PC can meet this requirement alone or by working with other PCs.				
Tom Bowe	PJM Interconnection, L.L.C.	2	Negative	SDT must define "design assessment". Is it different from every other one of the other assessments conducted by the PC? Without clarification an RE is left with these questions: Is the requirement to conduct an assessment? Or is it to conduct an assement that sucessfully meets R3? Is the PC non-compliant when its area's assets can not resolve the studied condition? Additionally, R12 is unclear in what it means by "event actuation". Is the objective to run an assessment; or is the objective to "design" a solution to islands created during a planning assessment. Clarify meaning of event actuation. R11 can be read to mean "when that event occurred in the real system (i.e. was actuated) then an event analysis must be considered; or it can mean when an assessment shows the creation of an island, then the PC must devise a process or procedure to correct the incident within 1 year. The text is awkward.
Response: The objective of the design assessment is to verify that the design of the UFLS program satisfies R3. For the purposes of PRC-006, the design assessment needs to be distinguished only from the event assessment, which is an after-the-fact analysis of a UFLS event per R11. There are no other assessments required by this standard. It is required to conduct an assessment that shows the UFLS program design satisfies R3 for each of the identified islands from R2. A PC would be non-compliant if its UFLS program cannot satisfy the performance curves in the Attachments up to a 25 percent imbalance between load and generation while considering the sub-points specified in R4. The objective of the event assessment is to analyze events after-the-fact. Event actuation is the time when the event was initiated. The point of R12 is to follow up after an event assessment if the event assessment indicated that the UFLS program did not perform as well as expected, or that improvements may be possible. It is not required that improvements be made, only considered. R11 means "when that event occurred in the real system (i.e. was actuated) then an event analysis must be considered." The PC does not need to "devise a process or procedure to correct the incident within 1 year," though a PC may consider changes to the UFLS program design that might improve its performance in future events of a similar nature in R12.				

Voter	Entity	Segment	Vote	Comment
Mark Ringhausen	Old Dominion Electric Coop.	4	Negative	See my comments in the VRF/VSL ballot.
Response: Please see the SDT response to your comments in the VRF/VSL non-binding poll.				
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Negative	See WECC comments
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	Several issues still need to be addressed in previously submitted comments. 2. This standard is too complicated and should be simplified to the following requirements; a documented Planning Coordinator (PC) UFLS plan, data provided to the PC, the PC should determine minimum design characteristics, entities should verify through simulation that the plan works as designed, and entities should provide their plan to adjacent interconnected NERC registered entities as evidence of coordination. 3. The performance curves the attachments should clearly state what approximately expected loss of life is being imposed on generator owners / operators to meet the curve expectations. Is the Generator under frequency trip model curve expecting a 5% or 10% loss of life probability per under frequency event for each unit? Generator Owners / Operators need to understand what kind of risk a standard imposes to make decisions on how best to comply with NERC standards, even if that decision is simply whether to change unit settings to meet a proposed curve or not.
Response: 1. Please see SDT response to previously submitted comments. 2. The SDT disagrees that this standard is too complicated. The requirements are necessary for reliability of UFLS programs. The commenter's overall suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, there would be no coordination between adjacent Planning Coordinators, no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays. 3. This is a subject for Project 2007-09 and the PRC-024-1 SDT. This standard is not applicable to Generator Owners. Loss of life depends on both the specifics of events and the specific characteristics of individual generators; the question is not one that can be answered with any certainty.				
David Schiada	Southern California Edison Co.	3	Negative	Support concerns identified by WECC.

Voter	Entity	Segment	Vote	Comment
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Keith Morisette	Tacoma Public Utilities	4	Negative	Tacoma Power is voting negative. We agree with the WECC position paper, which emphasizes that the UFLS should be focused on keeping the interconnection stable and not focusing on islands. The western interconnection currently has a single coordinated plan with support from its subregions. We continue to support this plan as the requirement for the interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Karl Bryan	U.S. Army Corps of Engineers Northwestern Division	5	Negative	The applicability section should list the Registered Entities that the Reliability Standard applies to. The approach used in this proposed reliability standard will lead to confusion.
Response: The SDT believes that the “UFLS Entities” approach is necessary in a continent-wide standard to accommodate the variety of historical practices in what entities implement UFLS.				
Alan Gale	City of Tallahassee	5	Negative	The attempt to define "annual" in R6 forces me to maintain my negative vote. The definition of "annual" is a very touchy subject. It determines compliance or non-compliance in a lot of standards. For those entities that have defined it internally, we are trying to impart some "defenition" to our procedures and policies. This issue is important enough that it should NOT be a last minute addition to a "second ballot" that was changed to reach concensus on all other issues. It should be defined above board and by a separate SAR if the SDT feels so strongly. I believe the commenter that asked about it was trying to find out what the "maintain" portion was refering to, not hte "annual".
Response: The change from “annual” to “at least once each calendar year, with no more than 15 months” was made merely to indicate what was intended by the term “annual”. This was a clarification from the previous posting of the standard to aid PCs in their interpretation of the requirement.				

Voter	Entity	Segment	Vote	Comment
William Mitchell Chamberlain	California Energy Commission	9	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. **Response**: A regional variance for the WECC interconnection has been included which should address these concerns. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. **Response**: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; “For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been

Voter	Entity	Segment	Vote	Comment
				provided. **Response**: Interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1.
Response: Please see the in-line responses.				
Ronald D. Schellberg	Idaho Power Company	1	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. WECC had a disturbance the was negatively impacted by the lack of cordination of UFLS between subregions. Continent wide Frequency-time curves would not account for the interconnection size.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Laurie Williams	Public Service Company of New Mexico	1	Negative	The current proposal still does not require coordination within the interconnection. The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As written the proposed standard creates the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement

Voter	Entity	Segment	Vote	Comment
John Tolo	Tucson Electric Power Co.	1	Negative	a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. BCH believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Joel T Plessinger	Entergy	3	Negative	The following are the reasons associated with our Negative Ballot. Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. In M3 it is unclear what action is intended by the phrase "including the criteria itself". Since the criteria is specified in R3, it is recommended that the phrase be deleted. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: "Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any

Voter	Entity	Segment	Vote	Comment
				identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators." We also recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint." The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. We also recommend that the High and Severe VSLs that contain the phrase "shall conduct and document" to read "conducted and documented". The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners

Voter	Entity	Segment	Vote	Comment
				provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information. The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the 500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events.
Response: The SDT agrees and has modified M3 to remove the phrase "including the criteria itself". The SDT has modified R5 and M5 to reflect the intent that only UFLS programs within the PC areas that are a part of the island under study need to work in conjunction to meet the performance requirement in R3. The SDT also modified R5 and M5 to remove the "concurrence" requirement and provide a means by which each PC can meet this requirement alone or by working with other PCs. The SDT has modified the VSLs for R11 to make these corrections. The SDT considered this and decided that the program reassessment is a binary task which automatically makes this a severe violation if not completed within the 5 year timeframe. The SDT has modified R13 to eliminate any duplication between R13 and R11. Requirement R3 has been modified to specifically indicate that the UFLS program must include "**notification** of and a schedule for implementation" in support of your suggestion. The SDT has added R14 which now requires the UFLS entities be notified of a comment period and for the PCs to respond to those comments prior to a UFLS program becoming effective. The SDT modified the implementation plan to state, "Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1." Per the implementation plan, the requirement to model data from the GOs is not mandatory until after the GOs are required to provide the data by PRC-024. This is similar to the requirement to model the BES by the TPL standards, while the requirement by entities to provide the data used to model the BES is contained in the MOD standards. The existing standard PRC-009, which this standard is intended to replace, currently requires that an assessment be performed for all events regardless of size. The SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the requirement the same or better than what exists today.				
Kim Warren	Independent Electricity System Operator	2	Negative	The IESO maintains its NEGATIVE vote in this ballot for the following main reasons: Criteria for Selecting Generators for Simulation Modeling

Voter	Entity	Segment	Vote	Comment
				Requirement R4 defines criteria for identifying generating units to be included by the Planning Coordinator (PC) in its periodic UFLS design assessment however we believe these criteria are insufficient. In response to other commenters the SDT stated "The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of Attachment 1." We are concerned about this assumption regarding the effectiveness of the NERC 20/75 MVA criteria since this is untrue in Ontario. In Ontario at least 2600 MW of generation (about 10% of generation in Ontario) would currently not be covered by these criteria and this amount is expected to increase as a result of provincial generation procurement initiatives. It is doubtful whether it would be possible to design an effective UFLS program with this much uncertainty. With increased penetration of renewable energy sources many of which may fall below the 20/75 MVA threshold, this problem is likely not unique to Ontario. We therefore believe the NERC standard needs an explicit mechanism for PCs to impose more stringent requirements when necessary to achieve the purpose of the standard. Generator Frequency Trip Curves The IESO was not satisfied with the SDTs response to our comment regarding evidence supporting the need for the overfrequency trip modeling curves proposed in this standard. We would also like to see similar justification for the underfrequency trip modeling curves. Although these curves have been proposed in PRC-024 and have not yet been approved, they are nevertheless referenced in the version of PRC-006-1 currently posted for ballot. Our concern is that these unapproved curves directly impose constraints on the Planning Coordinator in the design of its UFLS program. Imposing an unsubstantiated overfrequency constraint may cause unnecessary generator tripping, and may seriously interfere with the ability of PCs to develop a practical ULFS program particularly in light of the issues surrounding applicability mentioned above. We believe these two interdependent standards should either go to ballot together so that any issues regarding the curves could be adequately ventilated or PRC-006 should be changed to remove coupling to PRC-024. In brief, a standard should not be balloted when it depends on the information/requirement in another standard which has not been developed/approved. Gradual Decline in Reliability Standards Experience in NPCC working groups in this matter has shown it will be difficult to hold on to more stringent Regional or Area standards with PRC-006 in its present format.

Voter	Entity	Segment	Vote	Comment
				For example the NPCC generator underfrequency “do-not-trip” curve is lower (more onerous) than that required by NERC. Within the NPCC UFLS standard drafting team there was a natural tendency to harmonize the NPCC draft UFLS standard with the draft NERC PRC-006 curve, rather than to maintain NPCC’s more stringent approved criteria (Directory #12). While such sentiments have not prevailed thus far, if the NERC standard is passed in its present format, weakening of the NPCC standard would be inevitable with the unintended consequence of reduced reliability in the NPCC portion of the Eastern Interconnection.
Response: A regional variance can and should be considered by IESO. A variance could be more stringent than the level of detail and the adaptability to local conditions that a continent-wide standard can practically attain. Justification for both over and under frequency generator tripping curves is from manufacturer’s recommendations on acceptable durations at high and low frequencies. The curves were also chosen in recognition of existing legacy region guidelines on generator durations. These curves will become approved upon the approval of either PRC-006 or PRC-024, which ever is approved first. Further information on curve justification, or the need to modify a curve, should be asked of the PRC-024 SDT. The two teams have coordinated to the degree necessary to establish consistency, but cannot impose on each others schedules. The situation of interdependence of standards is not unique to PRC-006 and PRC-024. For example, compliance to TPL standards is dependent on system modeling data required under MOD standards. There is a limit as to what a continent-wide standard can achieve for the reliability concerns of an area without unduly imposing constraints on other areas that do not need tighter constraints. A variance may be the appropriate mechanism for addressing IESO’s concerns.				
Donald S. Watkins	Bonneville Power Administration	1	Negative	The primary concern identified in the first position paper is that the proposal does not require coordination within individual interconnections. The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is

Voter	Entity	Segment	Vote	Comment
Dana Cabbell	Southern California Edison Co.	1	Negative	problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. WECC believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
John Canavan	NorthWestern Energy	1	Negative	The primary concern identified is that the current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. **Response**: A regional variance for the WECC interconnection has been included which should address these concerns. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. **Response**: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer
John C. Collins	Platte River Power Authority	1	Negative	
Terry L Baker	Platte River Power Authority	3	Negative	
Glen Reeves	Salt River Project	5	Negative	

Voter	Entity	Segment	Vote	Comment
				loads should be excluded from curtailment for public health, safety and/or security reasons. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided. **Response**: Interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Tim Kelley	Sacramento Municipal Utility District	1	Negative	The primary concern identified is that the proposal does not require coordination within individual interconnections. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of “competing” uncoordinated underfrequency load shedding programs for a single event.
James Leigh-Kendall	Sacramento Municipal Utility District	3	Negative	
Mike Ramirez	Sacramento Municipal Utility District	4	Negative	

Voter	Entity	Segment	Vote	Comment
Bethany Wright	Sacramento Municipal Utility District	5	Negative	
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Michael J. Haynes	Seattle City Light	5	Negative	The primary concern identified is that the proposal does NOT require coordination within individual interconnections. The standard references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. The standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within RROs to adopt the Off-Nominal Frequency Load Shedding and Restoration Plans, modified as may be necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within interconnections.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Negative	The primary concern is that the current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Jerome Murray	Oregon Public Utility Commission	9	Negative	The proposed standard does not require coordination within individual interconnections. The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning

Voter	Entity	Segment	Vote	Comment
				Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. The standard needs to require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. For example, this would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Scott Kinney	Avista Corp.	1	Negative	The proposed standard does not require coordination within the interconnection. The standard should require the PCs within an interconnection to develop a coordinated UFLS plan.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Jerry W Johnson	South Mississippi Electric Power Association	5	Negative	The requirement seems to require the installation of facilities rather than just relays. 16 USC 824o (a)(3) gives NERC the authority to regulate existing facilities and planned additions or modifications to those facilities, not to prompt or require modifications or additions to the existing facilities. Criteria are never actually defined in the requirements. Planning Coordinator footprints are not established. What does "annually maintain" mean? Does it mean the Database requires annual updates, annual reviews or just to provide a database annually? Frequency excursions precede an islanding event. I.e. low frequency initiates UFLS which should prevent an unintentional islanding event. The wording of this requirement makes it seem like the islanding event occurs first and causes the UF. Measures are too vague, lacking specifics, and not performance-based.

Voter	Entity	Segment	Vote	Comment
				This would leave too much up to the Auditor's interpretation. Measures are only valuable if they contain specific targets or specifications that clarify how an entity will be deemed to be compliant with the standard as written. Measures which merely repeat the standard with the inclusion of "shall have evidence such as..." are not very useful. Measures should be explicit, detailed, consistent, and provide useful guidance to entities. These measures do not provide any useful guidance beyond what is specified in the requirement itself. M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that the phrase be deleted. M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. The graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curves data points The standard lacks guidance as to what the trip settings should be. It is not clear as to how Attachment 1 should be used and doesn't provide specific detail for under frequency set points. Neighboring Planning Coordinators will be making requests and setting criteria for the local planning coordinators and associated UFLS entities. We do not agree with the text "any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating." It is not clear what is included in automatic switching. This requirement is so vague that it does not appear to add anything in addition to the UFLS program design that it is intended to address. It appears that anything that R10 may be designed to address is already covered by R9.
Response: This standard is not out of line with expectations for standards in general. The proposed standard does not require the installation of facilities or relays. The SDT clarified this by adding the word "existing" in front of capacitor banks, Transmission Lines, and reactors in Requirement R10 to clarify that the intent. The SDT disagrees that the jurisdiction of Planning Coordinators and their footprints has not been established. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. Annually maintain means annual updates, though				

Voter	Entity	Segment	Vote	Comment
not exclusively. The term “annual’ has been replaced with wording that is more specific. UFLS cannot be expected to mitigate island formation. Most interconnections are large enough that a decline in frequency low enough to cause UFLS operations is highly unlikely unless the interconnection is broken into islands. Most UFLS operations are seen to occur following island formation. R5 has been clarified to address the commenter’s concern. Attachment 1 now has the performance characteristic curve data points tabulated. The under and over frequency performance curves are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misconstrued as applying to UFLS relay set points. UFLS entities are not affected, nor will a Planning Coordinator need to make requests of them or set criteria for them as far as island identification is concerned. The SDT believes the text quoted by the commenter is necessary due to the wide range of island determination criteria (R1) that may be forthcoming. “Automatic switching of Elements” refers to switching of, among other Elements, cap banks to prevent excessive voltages. R10 has been modified to remove the confusion.				
Richard J. Padilla	Pacific Gas and Electric Company	5	Negative	The revised proposal still does not require a coordinated plan within the interconnection to eliminate islands. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. Further refinements or additional requirements to an Interconnection's Coordinated plan can be made to address scenarios that can cause islands as determined by studies that are made at the overall Interconnection level. The draft standard is also very prescriptive is some cases, going as far as specifying maximum Volts per Hertz limits in simulated studies of islanded scenarios, as well as frequency versus time envelopes or boundaries that specify acceptable over/under frequency excursions. These type of performance limits should be specified at the Interconnection level based on the characteristics of the Interconnection, not at the National level. The proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. The proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common

Voter	Entity	Segment	Vote	Comment
				denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Gregory J Le Grave	Wisconsin Public Service Corp.	3	Negative	The Standard is not ready for implementation because portions of the draft are difficult to interpret due to vague language. R5 and R13 use the phrase "reach concurrence". In addition, it isn't clear if the UFLS entities must have the Planning Coordinator's UFLS program implemented by the standard's effective date.
Response: Some of the more vague wording had been replaced with wording that is more specific such as in R7 and R10 in the previous draft. The SDT agreed that reaching concurrence could be problematic and modified R5 and R13 to address this concern in the previous draft and eliminated the phrase, "reach concurrence" in support of your suggestion. UFLS Entities only need to comply with the Planning Coordinator's schedule for application; the Implementation Plan does not apply to the UFLS Entities. (Please see Implementation Plan Proposed Effective Date)				
Mel Jensen	APS	5	Negative	The standard is too prescriptive. It requires that islands be formed and the underfrequency load shedding be designed to arrest the frequency in the islands and meet several requirements. While this is a valid approach, it is a very restricted and prescriptive approach. The islands formed in the study may not be the islands which actually form when the events happen. The under frequency load shedding scheme should be considered as a safety net and the Planning Coordinator should be given more flexibility. Most of the standard requirements should be guidelines.
Robert D Smith	Arizona Public Service Co.	1	Negative	
Response: A continent-wide standard can specify performance curves or it can specify UFLS design parameters; the SDT has opted for performance curves. This is the less prescriptive approach of the two. The standard does not require island formation, only identification of islands to serve as the basis for UFLS assessments. The standard does not require Planning Coordinators to predict islands that may occur in the future; it only requires criteria for island identification in order for the design assessments in R4 to be conducted. UFLS needs to arrest system frequency declines, whether as islands or the interconnection. Guidelines have no place in an enforceable standard. A continent-wide standard must identify requirements that are common to the four interconnections and the SDT believes the standard does that without being unnecessarily prescriptive.				

Voter	Entity	Segment	Vote	Comment
John Yale	Chelan County Public Utility District #1	5	Negative	The standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would ensure continued coordination for underfrequency events within each interconnection and prevent individual PCs from developing conflicting plans.
Chad Bowman	Public Utility District No. 1 of Chelan County	1	Negative	
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Frank F. Afranji	Portland General Electric Co.	1	Negative	The standard should require coordination of UFLS plans not merely allow it. We agree with the WECC position paper which elaborates on this coordination. UFLS coordination should occur at the regional level, not the Planning Coordinator level.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Dennis Sismaet	Seattle City Light	6	Negative	The standard, requirements, and measurements should reflect the uniqueness of the individual interconnections and not common, continent wide prescriptions. The primary concern identified in the first position paper is that the proposal does not require coordination within individual interconnections. The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of “competing” uncoordinated underfrequency load shedding programs for a single event. WECC believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be

Voter	Entity	Segment	Vote	Comment
				necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Michelle Rheault	Manitoba Hydro	1	Negative	This standard is not ready for ballot. See submitted comments.
Mark Aikens	Manitoba Hydro	5	Negative	
Daniel Prowse	Manitoba Hydro	6	Negative	
Response: Please see the response to your submitted comments.				
Pawel Krupa	Seattle City Light	1	Negative	This standard needs more work to define the areas that need an UFLS program, and who coordinates the programs.
Dana Wheelock	Seattle City Light	3	Negative	
Hao Li	Seattle City Light	4	Negative	
Response: The SDT has made conforming changes to the proposed standard. The SDT is leaving it up to the Planning Coordinators to develop the UFLS program requirements for their Planning Coordinator area.				
Michael Moltane	International Transmission Company Holdings Corp	1	Negative	To meet requirement R4 as written, we will need generator frequency relay data that will be required in the new PRC0024 which is not yet approved. The generator Owners need to be required to provide this data to the Planning Coordinator in this standard.
Response: The SDT recognizes that PRC-024 may be approved at a different time and has inserted a provision in the implementation plan document to account for that possibility. Generator applicability is deferred to PRC-024 to avoid double jeopardy.				
Linda Horn	Wisconsin Electric Power Co.	5	Negative	We appreciate the SDT adding R14 in an attempt to provide a feedback mechanism between the UFLS Entity and the Planning Coordinator

Voter	Entity	Segment	Vote	Comment
James R. Keller	Wisconsin Electric Power Marketing	3	Negative	regarding the UFLS program design. However, the UFLS program which is ultimately implemented by the UFLS Entity needs to be mutually agreed to between the Planning Coordinator and the UFLS entity. Requirements R9, R10, and R14 must be strengthened to reflect as such. The "mutually agreed to" concept would force checks/balances in the development of the UFLS program to avoid unfairly burdening a UFLS Entity while maintaining reliability. We continue to believe that only islands of significant size be considered for the design of a UFLS program and for simulation after an UFLS event. The SDT stated in its consideration of comments that "PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009." We believe that the SDT can place a threshold in the revised PRC-006 since it is replacing PRC-009.
Response: A requirement for entities to mutually agree with each other or work together causes one entity's compliance to be dependent on another's. This has generally been viewed as unacceptable by the industry. This standard does not preclude development of regional standards in a process that may involve all interested entities in the region. PRC-009, which R11 is due to replace, is already a FERC approved standard and requires an assessment for all events regardless of size. An SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the standard the same or better than what exists today. We have specific feedback from FERC that they would not approve PRC-006 with an event analysis threshold because they would view that as lowering the bar. Note that identification of islands for UFLS design assessments may use whatever threshold a Planning Coordinator believes is appropriate in satisfying R1.				
Anthony Jankowski	Wisconsin Energy Corp.	4	Negative	We appreciate the SDT adding R14 in an attempt to provide a feedback mechanism between the UFLS Entity and the Planning Coordinator regarding the UFLS program design. However, the UFLS program which is ultimately implemented by the UFLS Entity needs to be mutually agreed to between the Planning Coordinator and the UFLS entity. Requirements R9, R10, and R14 must be strengthened to reflect as such. The "mutually agreed to" concept would force checks/balances in the development of the UFLS program to avoid unfairly burdening a UFLS Entity while maintaining reliability. We continue to believe that only islands of significant size be considered for the design of a UFLS program and for simulation after an UFLS event. The SDT stated in its consideration of comments that "PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009." We believe that the SDT can place a threshold in the revised PRC-006 since it is replacing PRC-009.

Voter	Entity	Segment	Vote	Comment
				We expressed a concern that the standard could place a burden on the UFLS Entity to shed additional load to make up for generators that do not conform to the PRC-006/PRC-024 underfrequency/overfrequency tripping curves. "The SDT has addressed the matter of GO versus TO/DP obligation for non-conforming generators and has decided that, for the likely small amount of non-conforming generation, that it should be a small burden, if any, to be spread across multiple TO sand DPs." We do not believe that ignoring GO responsibilities due to possible small burden is acceptable, as in some areas the burden may be significant and unwarrented without an obligation on the generator.
Response: A requirement for entities to mutually agree with each other or work together causes one entity's compliance to be dependent on another's. This has generally been viewed as unacceptable by the industry. This standard does not preclude development of regional standards in a process that may involve all interested entities in the region. PRC-009, which R11 is due to replace, is already a FERC approved standard and requires an assessment for all events regardless of size. An SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the standard the same or better than what exists today. We have specific feedback from FERC that they would not approve the standard with a threshold because they would view that as lowering the bar. Note that identification of islands for UFLS design assessments may use whatever threshold a Planning Coordinator believes is appropriate in satisfying R1. On the question of Generator Owners versus UFLS Entities assuming the burden of non-conforming generators, the SDT had discussed this matter at length at an early stage in development of this standard and believed that the amount of non-conforming generation would be small because the generator tripping curves (Attachment 1) have been chosen based on the off-nominal frequency duration recommendations of major generator manufacturers and were also chosen in recognition of legacy region guidelines on generator tripping.				
Kathleen Goodman	ISO New England, Inc.	2	Negative	We believe that the applicability section, which states: UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers Excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This appears to be a missing link that needs to be addressed before the standard can be approved. Also, the standard is potentially in conflict with the work to be done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. This would present yet another example of lack of coordination on NERC Standards development.
Response: The draft of PRC-024-1 is applicable to Generator Owners and will have the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. Generator applicability is deferred to PRC-024 in order to avoid double jeopardy for				

Voter	Entity	Segment	Vote	Comment
Generator Owners. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. The SDT has coordinated with the PRC-024 SDT so that both PRC-006 and PRC-024 are using the same under and over frequency generator tripping curves.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	While we agree with the purpose statement of the draft UFLS standard, we are voting negative. First, the standard goes much farther than the purpose statement. It is too prescriptive and includes too many administrative requirements. The new R14 is completely an administrative requirement that establishes a stakeholder process which has no reliability benefit. Furthermore, FERC Order 890 already requires transmission planners and planning coordinators to develop a stakeholder process. We agree that it makes sense to develop a frequency envelope to ensure it is coordinated across the Interconnection but question the need for Volts/Hz limit in 3.3. Secondly, the standard is overly complex. UFLS relays already are installed and coordinated today. The standard needs to reflect this reality and be made simple. We believe the standard should not be more complicated than establishing a requirement to have coordinated UFLS relays and making pertinent information available on the UFLS relays and program to the reliability entities with a need to know. The purpose can be accomplished in many fewer requirements than the 14 proposed requirements. Thirdly, we do not agree with the need to identify islands. While some areas of the BES have obvious islands such as the Florida peninsula, most of the BES does not form obvious islands and trying to predict how islands will form is arbitrary and unnecessary and provides no clear benefit to reliability. Other requirements that build on this islanding concept are unnecessary as well. For instance, we do not believe it is necessary or even beneficial to perform dynamic simulations of the UFLS program in areas that do not have natural islands. These simulations involve contingencies to such extremes that it stretches the limits of the analysis software and provides arbitrary results with questionable value. While these studies have been attempted in the past, some of these very studies have stated within their documentation that the island boundaries are completely arbitrary and don't correspond to any historical or conceivable islanding event. Furthermore, an effective UFLS scheme can be designed without simulations.
Response: Several commenters have expressed concerns that a Planning Coordinator can devise a UFLS program design and implementation				

Voter	Entity	Segment	Vote	Comment
schedule without any consideration of input by Distribution Providers or Transmission Owners before those plans are finalized. R14 establishes a peer review to at least partially address those concerns. Peer review procedures such as R14 are used elsewhere in approved NERC standards, specifically FAC-010 and FAC-011. The procedure has industry support. It allows Transmission Owners and Distribution Providers to at least have some say in what they will be obligated to implement. The Order 890 stakeholder process does not cover UFLS. Excessive V/Hz may cause unnecessary tripping of generation that may exacerbate an already precarious underfrequency condition. The SDT believes that this threat to UFLS effectiveness should not be overlooked. The SDT disagrees that this standard is too complicated. The requirements are necessary for reliability of UFLS programs. The commenter's suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, there would be no coordination required between adjacent Planning Coordinators, no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays. Islands, whether arbitrary or real, need to be identified in order to conduct UFLS design assessments. The SDT agrees that effective UFLS can be designed without simulations, but that is not the only means. Simulations are necessary to at least supply the evidence that a UFLS design can be effective.				
Paul Rocha	CenterPoint Energy	1	Negative	With regards to the proposed PRC-006-1; CenterPoint Energy is concerned about the overly prescriptive nature of this proposal and cannot support it in its present form. In particular, a requirement to identify areas that "may Island" might, arguably, make sense for a large interconnection such as the eastern or western interconnect, but it makes no sense for a smaller interconnect such as ERCOT that, essentially, is already an island for the purposes of this standard. Even for the larger interconnections, there are limitless possibilities of potential "islands" that could occur given certain combinations of contingencies. Since it is impractical to identify every conceivable island, it is unclear what level of diligence and documentation would be required to demonstrate to an auditor's satisfaction that the responsible entity has reasonably identified areas that "may" island. This ambiguity and subjectivity is contrary to objective number 2 in the Project Background to develop a standard "with clearly defined requirements and unambiguous language".
Response: All that is required concerning island identification (R1, R2) is to devise some criteria considering historical events and system studies and use those criteria to identify some islands. This does not mean that every conceivable island must be identified. The criteria can be as simple or elaborate as a Planning Coordinator desires. The SDT does not believe this is overly prescriptive, nor does it believe that it is ambiguous. However, island identification is admittedly subjective and it is difficult to offer more specific guidance in the standard without limiting flexibility and adaptability to characteristics specific to a region or interconnection.				
Gregory L Pieper	Xcel Energy, Inc.	1	Negative	Xcel Energy believes that the standard still contains many issues that are not clear and need to resolved. Among these issues is the mapping of PC to subordinate entities in areas where a regional entity or RTO has not
Michael Ibold	Xcel Energy, Inc.	3	Negative	

Voter	Entity	Segment	Vote	Comment
Liam Noailles	Xcel Energy, Inc.	5	Negative	taken on the PC role. Also, there are concerns around how small generators (less than the threshold specified) are addressed. Detailed comments were submitted to NERC with the concurrent comment period
David F. Lemmons	Xcel Energy, Inc.	6	Negative	
Response: Please see SDT response to these comments on the other comment form. The SDT disagrees that the mapping of Planning Coordinators to subordinate entities is a significant issue. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. This standard does not apply to Generator Owners, but this SDT has coordinated on the development of PRC-024 with that SDT. Although this has long been a subject of debate, the SDT generally believes that generators smaller than the Statement of Compliance Registry thresholds can be omitted in UFLS design assessments without significantly compromising reliability. GOs below the threshold could be registered if necessary by a regional entity for reliability according to the Compliance Registry Criteria.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Affirmative	
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Affirmative	
Harold Taylor, II	Georgia Transmission Corporation	1	Affirmative	
Richard J. Mandes	Alabama Power Company	3	Affirmative	1. The lower VSL for R11 is incorrect. It assigns a lower violation for meeting the requirement. This lower VSL should be deleted. 2. In the 2nd paragraph of the high VSL for R11, change "shall conduct and document" to "conducted and documented". 3. In the last paragraph of the severe VSL for R11, change "shall conduct and document" to "conducted and documented".
Anthony L Wilson	Georgia Power Company	3	Affirmative	
Gwen S Frazier	Gulf Power Company	3	Affirmative	
Don Horsley	Mississippi Power	3	Affirmative	
Horace Stephen Williamson	Southern Company Services, Inc.	1	Affirmative	
Response: Thank you for your comment. The SDT has modified the VSLs for R11 to make these corrections.				
Edward P. Cox	AEP Marketing	6	Affirmative	AEP has provided some general comments to the last posting.
Response: Thank you for your support.				

Voter	Entity	Segment	Vote	Comment
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved. This standard seems to be contrary to FERC's stated concern with NPCC(Oct. 2009 Washington DC meeting) to develop a standard that can support the program it was designed to enforce.....the applicability as stated in the standard and by NERC registry criteria restricts and excludes the need for GO's that may in aggregate be necessary for a reliable UFLS program, to adhere to the standard. The standard also is potentially in conflict with the work being done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. Sufficient coordination on NERC Standards development needs to occur on a going forward basis.
Response: Thank you for your support. The draft of PRC-024-1 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. Generator applicability is deferred to PRC-024 in order to avoid double jeopardy for Generator Owners. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. The SDT has coordinated with the PRC-024 SDT so that both PRC-006 and PRC-024 are using the same under and over frequency generator tripping curves.				
Saurabh Saksena	National Grid	1	Affirmative	At present, the proposed implementation plan language describes a one year phase-in period for compliance that is intended to provide the Planning Coordinators with sufficient time to (i) develop and/or modify UFLS programs; and, (ii) to establish an implementation plan for all required equipment changes. It must be recognized that any implementation plan would probably cover a multi-year period reflecting the time required to perform the engineering, purchasing, installation, and testing phases associated with implementing new and/or modified UFLS schemes. As an example, NPCC has already implemented a Region specific UFLS Program incorporating a six year UFLS implementation plan, with year one of the plan having ended June, 2010. As such, NPCC is concerned with how the final language included in the NERC UFLS implementation plan might impact the NPCC-specific UFLS Implementation Program. NPCC will closely monitor NERC's efforts in developing its UFLS Reliability Standard so NPCC can appropriately include the continued implementation of its Region specific UFLS Program within the NPCC Regional Standard PRC-006-NPCC-1, the required Regional Entity companion standard to the NERC UFLS Standard.
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your support. The SDT believes that NPCC's six-year implementation plan will not be adversely affected by this standard or this standard's implementation plan.				
Louis S Slade	Dominion Resources, Inc.	6	Affirmative	Dominion appreciates the changes the SDT made to address our concerns.
Response: Thank you for your support.				
Tim Hattaway	PowerSouth Energy Cooperative	5	Affirmative	R10 needs further clarification. One would assume that the "element" referred to is one that is essential to the correct function of the UFLS scheme?
Response: "Automatic switching of Elements" refers to switching of, among other Elements, cap banks. The intent here is for switching necessary to avoid excessive voltage following UFLS operations. R10 has been modified to remove the confusion.				
Charles H Yeung	Southwest Power Pool	2	Affirmative	SPP votes in favor of the standard but directs the SDT to the ISO RTO Council comments submitted on the PRC-006 standards. We are concerned the generator owner/operators are not included as applicabile registered entities to this standard but understand there is a separate effort to develop generator owner/operator standards that could require them to provide UFLS data to Planning Coordinators. Absent that enforceable requirement, PCs could be subject to inappropriate violations if a GO fails to provide needed UFLS data. In order to move new standards forward that rely on other yet to be approved standards, NERC must take a sensible approach in enforcement of requirements if a violation is found to be caused by gaps in enforceable standards as mentioned.
Response: Thank you for your support. There is a requirement in the draft PRC-024-1 for Generator Owners to supply Planning Coordinators and other entities generating unit over and under frequency trip settings. The SDT recognizes that PRC-024 may be approved at a different time and has inserted a provision in the implementation plan document to account for that possibility. Generator applicability is deferred to PRC-024 to avoid double jeopardy. The number of non-conforming generators is expected to be small and should not cause a compliance issue for Planning Coordinators in an interim period, if any, before Generator Owner data becomes available to them. Generator tripping curves common to PRC-006-1 and PRC-024-1 (Attachment 1) have been chosen based on the off-nominal frequency duration recommendations of major generator manufacturers and were also chosen in recognition of legacy region guidelines on generator tripping.				
Kenneth D. Brown	Public Service Electric and Gas Co.	1	Affirmative	The PSEG Companies are voting affirmative on this standard with the following understanding of the intent of these Standards. PSEG believes

Voter	Entity	Segment	Vote	Comment
Jeffrey Mueller	Public Service Electric and Gas Co.	3	Affirmative	that the Standard Drafting Team has appropriately charged the Planning Coordinators with the responsibility for development and coordination of UFLS programs and assessments. The PCs are best positioned to carry out these responsibilities as part of their planning activities. In many areas such as ISOs and RTOs the individual TOs and DPs do not have the regional view that is necessary to successfully design, coordinate and assess UFLS programs. TOs and DPs role would be primarily to provide data such as forecast peak load and installed UFLS capability upon request of the PCs, and to install and maintain the TO/DP's share of UFLS capability as determined by the PC. PSE&G will support the Planning Coordinators with system information and compliance data as required to meet their needs.
Response: Thank you for your support.				
Steven Grego	MEAG Power	3	Affirmative	The reference to "automatic switching of Elements" needs to be clarified. Does it mean that the TO needs to switch capacitor banks, or does it refer to the breakers equipped with UF relays? If it is referring to capacitor banks, is this applicable near major generation busses?
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Affirmative	
Response: Yes, "automatic switching of Elements" refers to switching of, among other Elements, cap banks. R10 has been modified to remove the confusion. Cap bank switching may be particularly applicable near generation if excessive V/Hz is observed following UFLS operations.				
Silvia P Mitchell	Florida Power & Light Co.	6	Affirmative	This revised definition is better written.
Response: Thank you for your support.				
Bruce Merrill	Lincoln Electric System	3	Abstain	LES appreciates the Drafting Team's addition of R14 to allow for stakeholder input into the development of the PC's UFLS program. However, LES believes that the stakeholder process could be better defined to reflect a more formalized process similar to that of the NERC standards development process.
Eric Ruskamp	Lincoln Electric System	6	Abstain	
Response: This standard does not preclude development of regional standards in a process that may involve all interested entities in the region.				
Jeff Nelson	Springfield Utility Board	3	Abstain	SUB provided some responses on the Comment Form.
Response: Please see SDT responses to comments on the comment form.				

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Successive Ballot — Underfrequency Load Shedding (Project 2007-01)
Date of Successive Ballot: September 24, 2010- October 4, 2010

Summary Consideration: A successive ballot was conducted from September 24-October 4, 2010 and achieved a quorum and an overall weighted segment approval of 81.72%. There were some comments submitted with both affirmative and negative ballots, and all of those comments and the drafting team's consideration of those comments, are included in this report.

Some balloters suggested that the SDT clarify the term "regional boundaries" in Requirement R2 part 2.3. The SDT made a minor change intended to clarify that "regional boundaries" are the "regional entity area boundaries". The SDT considers this change to be a clarifying change that does not substantively change the standard.

Some comments indicated that the Planning Coordinator (PC) should be replaced by the Reliability Coordinator (RC). Wide Industry support exists for the Planning Coordinator as the correct Functional Model entity to develop the UFLS program based on its wide-area view and expertise in the studies necessary to assess UFLS program performance. In addition, the assignment of these functions to the Planning Coordinator is consistent with the role as defined in the Functional Model Version 5 which says that the Planning Coordinator is: "The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas…" The Reliability Coordinator is defined as: "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." The Reliability Coordinator is not the appropriate entity to establish and assess UFLS programs which is a planning function not a real-time function.

Several comments indicated a concern that Requirement R14 does not go far enough and in other cases is not necessary on the basis that it is an administrative requirement. The SDT added Requirement R14 in response to comments received during the initial ballot conducted in July, 2010 that it was necessary for the Planning Coordinators to involve the UFLS entities in the development of the UFLS program and schedule for implementation. The SDT believes the UFLS Entities should have input into the process as provided in Requirement R14, but Requirement R14 cannot go further to require mutual agreement or concurrence due to the problem that one entity's compliance would be dependent on what another entity does.

Some comments indicated that the Transmission Owners(TOs) in the applicability is confusing considering they are included in "UFLS Entities" and proposed to modify the applicability section to clarify the distinction between 4.2 and 4.3 in the Applicability Section. The SDT thinks that Requirement R10 clearly establishes what is required (and why) of the Transmission Owners: provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program determined by the Planning Coordinator(s).

Several comments indicated that Requirements R8, R9 and R10: should require that the format and schedule be agreed upon by all the parties involved. Including a requirement in a standard that requires that entities agree with one another is problematic. It is possible that such a requirement could lead to compliance concerns because to fulfill the obligation of the requirement an entity will be dependent on another organization to be in compliance with the requirement. The alternative is that including all entities could potentially lead to compliance issues if they cannot reach agreement making all entities non-compliant.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	(1) Requirement R3 should be modified, as stated below, to reflect the need for the Planning Coordinator to recognize and use existing UFLS programs, which have been in place and functional for perhaps decades, as a starting point, rather than 'starting over from scratch': " R3. Each Planning Coordinator shall consider the existing UFLS programs that are in place, and working with the UFLS entities and Transmission Owners , propose modifications to the UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, as needed to meet the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load - actual generation output) / (load)], of up to 25 percent within the identified island(s). " **Response**: The SDT expects that Planning Coordinators will not be developing modifications to UFLS programs unless an assessment pursuant to Requirement R4 identifies deficiencies that prevent meeting the performance characteristics in Requirement R3. Although the proposed revision suggests that Planning Coordinators consider existing programs, it does not provide any additional incentive beyond the practical incentive that already exists with the existing requirement. In addition, the SDT added explanatory examples in the implementation plan to illustrate that during the phase-in period a Planning Coordinator may validate the existing program against the performance requirements to ensure the performance characteristics in Requirement R3 are met. (2) Requirement 14 only requires Planning Coordinator to provide a written response to the written comments submitted by the UFLS entities and Transmission Owners before finalizing its UFLS program. While R14 is a step in the right direction, it still provides the Planning Coordinator the authority to develop and pursue items 14.1, 14.2 and 14.3 without active participation of the UFLS entities and Transmission Owners in the process. An opportunity to submit written comments and receive written response is not the same as active involvement. The language of R14 should be modified such that the Planning Coordinator is required to provide for greater involvement of and coordination with the UFLS entities and

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				Transmission Owners in developing items 14.1 -14.3. **Response**: A requirement that the Planning Coordinators provide for involvement of and coordination with the UFLS entities and Transmission Owners does not provide a clear measure as to what constitutes "involvement" and "coordination." Industry comments have supported that the Planning Coordinator is the correct Functional Model entity to develop the UFLS program based on its wide-area view and expertise in the studies necessary to assess UFLS program performance. The SDT believes the UFLS Entities should have input into the process as provided in Requirement R14, but cannot go further to require mutual agreement or concurrence due to the problem that one entity's compliance would be dependent on what another entity does. (3) The previous version included curves out to 10,000 seconds where generators trip frequencies had to be modeled. This version includes revised curves, which is ok; but, a clarification is needed on whether or not to include generators with trip times longer than 100 seconds **Response**: Requirement R3 indicates that simulations must be run for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached. The time axis on the graphs in Attachment 1 was reduced to reflect this requirement. It is not necessary to model underfrequency protection that would operate beyond the end of the simulation.
Paul B. Johnson Raj Rana Brock Ondayko Edward P. Cox	American Electric Power American Electric Power AEP Service Corp. AEP Marketing	1 3 5 6	Affirmative	In R2.3 suggest clarification be provided for the terms "regional boundaries"
Response: The SDT made a minor change intended to clarify that "regional boundaries" are the "Regional Entity area boundaries" in Requirement R3 part 2.3.				
Robert D Smith	Arizona Public Service Co.	1	Negative	The standard is complicated and too prescriptive. It does not allow enough flexibility to Planning Coordinator and does not account for safety nets.

Voter	Entity	Segment	Vote	Comment
Mel Jensen	APS	5		
Response: The SDT cannot fully consider the comment without additional detail. However, the SDT believes the approach taken provides the Planning Coordinators the greatest flexibility by defining what performance characteristics the UFLS program must meet to support system reliability rather than defining how the Planning Coordinators are to design the UFLS program.				
Paul Rocha	CenterPoint Energy	1	Negative	In response to previous CenterPoint Energy comments, the SDT admits that island identification is subjective; however, the SDT has not made any significant changes in PRC-006-1 Draft 5 to address the confusion on island identification. In addition, the recent Webinar (September 17, 2010) stated "PC must have some criteria (R1), though not necessary that the criteria produce islands." R2 requires a PC to identify one or more islands. Again from the Webinar; "One island must be the regional footprint (R2.3) so as to preserve existing coordination of UFLS at regional level." Since R1 does not require the criteria to produce islands and R2 only requires one island, i.e. the regional footprint could suffice, it appears R1 and R2 require activities that are unnecessary and produce no meaningful product and therefore offer no enhancement of reliability to the BES above the current Standard. A reliability standard should have clearly defined requirements. CenterPoint Energy believes the islanding requirements are low level facilitating requirements that are more appropriately and inherently monitored under various higher-level performance-based requirements. Essentially, requirements R1 and R2 should be deleted. Alternatively, if the SDT feels compelled, for whatever reason, to maintain the proposed islanding requirements, CenterPoint Energy proposes adding wording to R1 along the lines of the SDT comments in the Webinar (September 17, 2010) and the Consideration of Comments. That is, concerning the criteria required for R1, clarify that it is"... not necessary that the criteria produce islands" and that R1 "does not mean that islands must be identified from a Planning Coordinator's R1 criteria."
Response: Past system disturbances including the August 14, 2003 Northeast Blackout demonstrate the value of identifying and assessing islands that may form. Identification and assessment of islands other than along regional boundaries, where they may form, offers a significant enhancement to reliability and justification for Requirements R1 and R2. The identification of at least one island is essential to serve as the basis for designing and assessing the UFLS program. The intent of R1 is the identification of islands that may have more than an insignificant probability of occurring and it is therefore desirable to use these, if there are any, in assessing UFLS program performance. However, if none are identified by the R1 criteria, that is still acceptable and the region or interconnection alone will suffice as the basis for the design assessments. So the result of R2 should be at least one island as explained during the webinar. Again, the SDT recognizes that it is possible that the R1 criteria yield no islands which is further justification, besides regional coordination, for including Requirement R2 Part 2.3 as it is important that at least one island serve as the basis for designing the UFLS program.				

Voter	Entity	Segment	Vote	Comment
Danny McDaniel Bryan Y Harper Matthew D Cripps	Cleco Power LLC Cleco Utility Group Cleco Power LLC	1 3 6	Negative	In the Applicability section of PRC-006, Planning Coordinator should be changed to Reliability Coordinator. This would allow the entity which has the highest authority to determine what is best for its region. **Response**: Wide industry support exists for the Planning Coordinator as the correct Functional Model entity to develop the UFLS program based on its wide-area view and expertise in the studies necessary to assess UFLS program performance. In addition, the assignment of these functions to the Planning Coordinator is consistent with the role as defined in the Functional Model version 5 which says that the Planning Coordinator is: "The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas..." The Reliability Coordinator is defined as: "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." The Reliability Coordinator is not the appropriate entity to establish and assess UFLS programs which is a planning function not a real-time function. For EOP-003, R5, Severe VSL, please add the statement "as directed by the requirement" as noted in the other requirements VSL. **Response**: The proposed change is outside the scope of the supplemental SAR for this project to revise the requirements specific to Underfrequency Load Shedding in EOP-003-1 to remove inconsistencies and redundancies with PRC-006-1.
Robert Martinko Kevin Querry Kenneth Dresner Mark S Travaglianti	FirstEnergy Energy Delivery FirstEnergy Solutions FirstEnergy Solutions FirstEnergy Solutions	1 3 5 6	Affirmative	FE appreciates the SDT's hard work on this project and is casting an Affirmative vote. Also, we offer the following comments and suggestions: We anticipate that Planning Coordinators and UFLS Entities will work together to reach consensus on the implementation schedules. However, we still believe that the standard or implementation plan should explicitly afford the UFLS entity at least 12 months to implement any new capital equipment, and at least 3 months to implement setting changes on existing equipment. Also, we believe that the standard should explicitly require that the PC solicit input into the final draft of the program from its UFLS Entities. **Response**: Thank you for your support. The SDT expects that the Planning Coordinators will consider input from the UFLS entities when establishing their UFLS program and schedule for implementation per Requirement R14 Part 14.1. The SDT also expects that as the Planning Coordinators fulfill their role as described in the Functional Model, including coordinating with the Transmission Owners and Distribution Providers, they will not make unilateral decisions without considering

Voter	Entity	Segment	Vote	Comment
Douglas Hohlbaugh	Ohio Edison Company	4		the input from the UFLS entities (as provided for in Requirement R14 or otherwise). The SDT debated on whether to include a minimum implementation time frame as suggested, but concluded that selecting a minimum time could still not guarantee sufficient lead time, the time frame must be based on the scope of the program modifications on a case-by-case basis, and any particular time frame would be difficult to justify for a continent-wide standard. Lastly, in the rare case of any concerns among the UFLS entities of the PC's UFLS program, we suggest an enhancement to require that the PC have a dispute resolution process. To incorporate our comments above, we have the following proposed wording for Requirement R14: "R14. Each Planning Coordinator shall meet the following during the development of a new UFLS program and during subsequent revisions of the program [VRF: Low][Time Horizon: Long-Term Planning]: 14.1. Submit an initial draft of its UFLS program for review and feedback by the identified UFLS Entity before the UFLS program is finalized. 14.2. Assure that the schedule for implementation of a UFLS program affords the UFLS Entity at least 12 months to achieve compliance for any required capital equipment expenditures and installations, and at least 3 months for any required settings changes to existing equipment. 14.3. Have and implement a dispute resolution for cases where the UFLS Entity and the Planning Coordinator cannot reach agreement on the UFLS program. **Response:** The SDT thinks that adding a requirement to establish a dispute resolution process would go too far in prescribing "how" the Planning Coordinator will fulfill its role rather than what needs to be accomplished to achieve reliability.
Claudiu Cadar	GDS Associates, Inc.	1	Negative	1. Applicability. 4.3. We do not agree with prior SDT response to comment. While SDT response indicates that 4.3 is intended for TOs that may need to switch equipment other than load, however we consider that 4.3 is a redundant assignment since reference to TOs controlling UFLS equipment already included in 4.2.2. We consider that TOs that own control / operate elements other than the UFLS equipments but identified in an UFLS program, should be considered as part of the same category "UFLS entities". However, if SDT wants to split the TOs into two categories based on the end-use load, and elements other than UFLS equipments, 4.3 should be reformulated to reflect the difference in between the two (this will help to point out to what TOs are the requirements applicable). We suggest adjusting 4.3 such as "Transmission Owners that own Elements identified in the UFLS program other than the UFLS equipment as established by the Planning Coordinators." **Response:** The SDT thinks that the Transmission Owner applicability is sufficiently

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				clear and that Requirement R10 clearly establishes what is required (and why) of the Transmission Owners: provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program determined by the Planning Coordinator(s). 2. Effective Date. 5. Depending on when this standard becomes mandatory and enforceable, it may fall between entities' budgeting periods. An 18 months implementation would allow for all entities to budget the funds necessary to implement the standard. **Response:** The SDT expects that the Planning Coordinators will consider input from the UFLS entities when establishing their UFLS program and schedule for implementation per Requirement R14 part 14.1. The SDT also expects that as the Planning Coordinators fulfill their role as described in the Functional Model, including coordinating with the Transmission Owners and Distribution Providers, they will not make unilateral decisions without considering the input from the UFLS entities (as provided for in Requirement R14 or otherwise). The SDT debated on whether to include a minimum implementation time frame as suggested, but concluded that selecting a minimum time could still not guarantee sufficient lead time, the time frame should be based on the scope of the program modifications on a case-by-case basis, and any particular time frame would be difficult to justify for a continent-wide standard. 3. Requirements. R2.3. The added wording, which although brings some clarification in how the regional boundaries will be established, can be confusing with respect to the elements included in the UFLS program when for simulation purposes there will be elements either integrated or excluded; the elements comprised in the assessment may not entirely match the list of elements identified by the UFLS program. We consider that the models used in simulation should reflect the correct topology and structure of the BES. **Response:** The R2.3 added wording (the last sentence of R2.3) is necessary because the contour of some sections of the Regional Entity boundaries in the Eastern Interconnection may cause difficulties when attempting to simulate each Regional Entity area as a single contiguous island. However, once island boundaries are adjusted by mutual consent, and such islands are thereby defined for purposes of UFLS design assessments, there should be no confusion as to which elements are in an island and which are outside, though it is true that UFLS

Voter	Entity	Segment	Vote	Comment
				program(s) of Planning Coordinator(s) of a different region may be represented in a portion of a Regional Entity island with adjusted boundaries. 4. Requirements. R8. We disagree with SDT response on previous comment. While all this flow of data requires coordination among the UFLS entities, TOs that own equipment as identified in the UFLS program and PCs, we suggest that the proper format and schedule should be agreed upon by all these parties involved, where the standard should specifically state this. Comment applies also to R9 and R10. **Response:** UFLS entities and Transmission Owners have opportunity for input on the schedule for implementation as provided for by R14. The requirement to supply data (R8) is not onerous and the SDT believes that as the Planning Coordinator may be receiving data from many entities, the PC should be able to determine the schedule and format for efficiency in processing the received data. While the standard does not set a certain schedule, can the SDT explain the timing in the corresponding VSL for R8 **Response:** The VSLs for R8 refer to days beyond the schedule (that is, date) specified by the Planning Coordinator to receive the data. Requirement R8 says that the Planning Coordinator will establish the format and schedule. The corresponding VSL is an after-the-fact element once the requirement has been violated and since the requirement is "time sensitive" the VSL must establish various levels of severity for non-conformance to the requirement. The VSLs were developed using the SDT Guidelines and conform to the NERC and FERC guidelines for VSLs. 5. Requirements. R5, R13. The addition of bullet-pointed methods to approach the coordination of the design assessment or event assessment should be followed by a comment period and written response such in case PCs have not reach the same conclusions of its own individual assessment, otherwise there will be no coordination in that case. We also suggest replacing the bullet points with numbers such as 5.1, 5.2, 5.3 / 13.1, 13.2, 13.3. **Response:** Unfortunately, a comment period cannot assure coordination either. A previous draft of the standard required Planning Coordinators to reach concurrence, but this was found to be unacceptable to a wide spectrum of industry commenters. Bullets points in a standard indicate that the entity has various options to select from to fulfill its duties as clarified by the term that precedes the list of bullets "through or by one of the following" in Requirement R5 and Requirement R13. Numbers in the standard establish a "must" list. The entities would be required to

Voter	Entity	Segment	Vote	Comment
				meet all the items on a numbered list. 6. New requirement / measure. The standard should include a requirement so the PCs to communicate their UFLS program, design / event assessment to UFLS entities and TOs involved (which own elements identified by the program or assessment). Appropriate measures for retaining evidence should be also included. **Response:** Requirement R3 includes notification to the UFLS entities of the UFLS program and schedule for implementation. Event assessments do not directly affect UFLS entities unless a redesign is in order in which case R3 would again require notification. Evidence retention is specified in the Compliance Section, D 1.2.
Michelle Rheault Greg C Parent Daniel Prowse	Manitoba Hydro	1 3 6	Negative	The current draft standard did not consider most Manitoba Hydro and MRO concerns submitted during the commenting period.
Response: The SDT considered all comments received during development of the standard. The SDT made many changes to the standard in response to industry comments. The SDT acknowledges that it did not modify the standard in response to every comment, but also notes that explanations were provided whenever the SDT decided not to modify the standard in response to comments.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	While the TPL note “b” approach has improved, MidAmerican has concerns that including the wording “review and acceptance” goes beyond the FERC Order 890 Order, process, and intent of including the an open review. Therefore, to align with FERC Order 890, the “review and acceptance” should be replaced with “subject to comment”. Anything more exceeds FERC Order 890 and the reason why the review process was included. In the end, Transmission Owning and Operating entities must have final say in the operation of the grid. Entities can comment, but cannot obstruct Transmission Owning and Operating entities from properly operating the grid or reliability could be reduced.
Response: The phrase “review and acceptance” does not appear in PRC-006-1. The SDT believes this comment may have been intended for another standard and inadvertently submitted as a comment to this ballot.				
Richard L. Koch	Nebraska Public Power District	1	Affirmative	Modeling criteria may need to be changed with the approval of PRC-024-1.

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your support. The SDT understands that the generator off-nominal frequency protection coordination curves that will be included in PRC-024 are the same as what is currently included in PRC-006. The intent by both teams is that these curves will continue to be coordinated going forward.				
Kenneth D. Brown Jeffrey Mueller David Murray James D. Hebson	Public Service Electric and Gas Co. Public Service Electric and Gas Co. PSEG Power LLC PSEG Energy Resources & Trade LLC	1 3 5 6	Affirmative	The PSEG Companies' vote to approve is based on the following understanding of the standards. The Planning Coordinator is responsible for development and coordination of the overall UFLS programs and assessments. Support from the Transmission Owners and other entities consists of providing the Planning Coordinator with data such as forecasted loads and installed UFLS capability upon request, and to maintain and modify the capability as required, with the understanding that the PRC-006-1 Requirement 14 process will address any TO or other entity concerns. Regarding requirements specified in PRC-006-1 Requirement 10, Planning Coordinators will need to confirm that any automatic switching of capacitors, reactors and particularly transmission lines will not be a detriment to local conditions as specified by the Transmission Owners. Switching of specific transmission lines could result in the further reduction of load in an island, compounding the overvoltage effects.
Response: The SDT agrees. Thank you for your comments and support of the standard.				
Keith V. Carman Janelle Marriott	Tri-State G & T Association, Inc.	1 3	Negative	Tri-State appreciates the hard work by the drafting team and its attempt to address the concerns of many entities by inserting a WECC variance. We also agree that a standard of this nature is necessary to ensure reliable operation of the Bulk Electric System. However, we believe that the functional entity responsible for developing and documenting the UFLS program should be the Regional Entity through its registration as the Reliability Assurer. The drafting team addressed earlier comments in that regard by stating that the drafting team had confirmed "that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5." We do not reach that same conclusion. We do not see any assigned function of the Planning Coordinator that includes UFLS plan development. The NERC Reliability Functional Model Technical Document-Version 5, however, does state that a representative task undertaken by the Reliability Assurer might be to "perform high-level evaluations, such as at a regional or Interconnection level, of protection systems as they relate to the reliability of the Bulk Electric System." FERC, when addressing PRC-006-0, also states in Order 693, Paragraph 1480 "The Commission expects that this function will pass from the regional reliability organization to the Regional Entity after they are approved." This

Voter	Entity	Segment	Vote	Comment
				comment would affect the Applicability section as well as nearly all the requirements in the continental standard and in the WECC variance.
Response: The SDT believes that the WECC variance specifically addresses this concern by requiring a single coordinated program in the WECC interconnection. The Planning Coordinators will need to work together on this coordinated, region-wide program. The SDT believes the Planning Coordinator is still the appropriate entity to perform this function. In addition, the assignment of these functions to the Planning Coordinator is consistent with the role as defined in the Functional Model version 5 which says that the Planning Coordinator is: "The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas…The Planning Coordinator is responsible for assessing the longer-term reliability of its Planning Coordinator area. While the area under the purview of a Planning Coordinator may include as few as one Transmission Planner and one Resource Planner, the Planning Coordinator's scope of activities may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities."				
John Tolo	Tucson Electric Power Co.	1	Negative	The primary concern identified is that the current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The WECC variance included with this most recent revision of the standard address most, if not all, of these concerns, which are specific to the WECC interconnection. Please review the justification for the WECC variance included with the ballot of draft 5 of the standard.				
Allen Klassen	Westar Energy	1	Negative	Not enough time for study completion and implementation.

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Response: The SDT believes that there is ample time to complete the study. The implementation schedule is set by the Planning Coordinator, not the standard.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	We thank the drafting team for its response to the issues raised during the last ballot. Notwithstanding our 'AFFIRMATIVE' vote on this occasion, we continue to have several concerns as follows: We believe the generating unit and facility capacities specified in Requirement R4 are not appropriate. In our view, as more renewable energy projects are developed in the future, the significance of generating units and facilities throughout North America that do not meet those thresholds will increase, as is the case in Ontario at present. We will pursue this issue as suggested, as a variance to the NPCC regional UFLS standard which is currently under development where we hope it will be adequately addressed. **Response**: Thank you for your support of the standard. We believe that pursuing this issue in a regional standard is appropriate if the NPCC system requires lower thresholds. Further, we view the generator overfrequency trip modeling curve as overly conservative. Having higher overfrequency trip thresholds is highly desirable since this will provide greater flexibility to the PC in designing its UFLS program in situations where over-generated islands are formed. We will pursue this matter further under Project 2007-09 - Generator Verification, as part of the continued development of PRC-024-1. We expect that if changes to this curve are made in PRC-024-1, they will be reflected in PRC-006-1. **Response**: Thank you for your support of the standard. We believe that pursuing this issue with the Generator Verification SDT is an appropriate method for pursuing your concern. If the overfrequency trip curve in PRC-024 is raised a SAR should be submitted to request corresponding changes to PRC-006. Finally, we would like to know what recourse a PC will have if it is unable to design an effective UFLS program due to the tight constraints imposed by the UFLS performance characteristics. **Response**: The SDT does not believe that designing a UFLS program that satisfies the performance curves for the required imbalance level will be a problem.
Jason L Marshall	Midwest ISO, Inc.	2	Negative	While we continue to agree with the purpose statement of the draft UFLS standard, we have continuing concerns regarding the draft standard that have not been resolved. We believe the standard goes much farther than the purpose statement, is too prescriptive, and includes too many administrative requirements. R14 is an

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				administrative requirement that establishes a stakeholder process which has no demonstrated reliability benefit. It should be removed. UFLS relays already are installed and coordinated today. The standard needs should be simplified to reflect this reality. We believe the standard should not be more complicated than establishing a requirement to have coordinated UFLS relays and making pertinent information available on the UFLS relays and program to the reliability entities with a need to know. The purpose can be accomplished in many fewer requirements than the 14 proposed requirements. **Response**: The simplified standard requirements suggested in this comment would constitute a fill-in-the-blank standard similar to the existing PRC-006-0 which the Commission did not approve in Order No. 693. The SDT believes the proposed standard does recognize existing programs and expects that Planning Coordinators will not be developing modifications to UFLS programs unless an assessment pursuant to Requirement R4 identifies deficiencies that prevent meeting the performance characteristics in Requirement R3. Ensuring coordination of UFLS relays is not as easy as just saying that UFLS relays shall be coordinated. The SDT believes the standard achieves a reasonable balance between prescription and autonomy. Though R14 is administrative and procedural, it has the support of many industry commenters as a means by which Distribution Providers and Transmission Owners may have input on what they will be required to implement and when. While we agree that it makes sense to develop a frequency envelope to ensure it is coordinated across the Interconnection, we do not believe there is a need for Volts/Hz limit in 3.3. **Response**: The SDT believes there is a need for V/Hz requirements because shedding load will cause voltages to climb, which may cause excitation systems / voltage regulators to reach the end of their range, which can lead to a V/Hz condition that could cause generators to trip through GSU protection or other similar protection systems. Tripping of generation due to preventable V/Hz conditions may exacerbate an already precarious underfrequency condition. The SDT believes that this threat to UFLS effectiveness should not be overlooked. We continue to disagree with the need to identify islands. While some areas of the BES have obvious islands such as the Florida peninsula, most of the BES does not form obvious islands and trying to predict how islands will form is arbitrary and unnecessary and provides no clear benefit to reliability. Other requirements that build on this islanding concept are unnecessary as well. For instance, we do not

Voter	Entity	Segment	Vote	Comment
				believe it is necessary or even beneficial to perform dynamic simulations of the UFLS program in areas that do not have natural islands. These simulations involve contingencies to such extremes that it stretches the limits of the analysis software and provides arbitrary results with questionable value. While these studies have been attempted in the past by some NERC regions, some of these very studies have stated within their documentation that the island boundaries are completely arbitrary and don't correspond to any historical or conceivable islanding event. Furthermore, an effective UFLS scheme can be designed without simulations. **Response**: Past system disturbances including the August 14, 2003 Northeast Blackout demonstrate the value of identifying and assessing islands that may form. Identification and assessment of islands other than along regional boundaries, where they may form, offers a significant enhancement to reliability and justification for Requirements R1 and R2. Islands, whether arbitrary or real, also need to be identified to conduct UFLS design assessments. The intent of R1 is the identification of islands that may have more than an insignificant probability of occurring and it is therefore desirable to use these, if there are any, in assessing UFLS program performance. However, if none are identified by the R1 criteria, that is still acceptable and the region or interconnection alone will suffice as the basis for the design assessments. The SDT agrees that effective UFLS programs can be designed without simulations. However, simulations are necessary to at least supply the evidence that a UFLS design can be effective and may supply insights toward a more effective design. We question the need for R11 and R13 given NERC's recent efforts to develop an event analysis process and focus on becoming a learning organization. NERC's process already compels registered entities to do their own event investigation and UFLS triggers are already included in Category 2. Why do we need requirements for event analysis in this standard as well? **Response**: The SDT originally planned to cover event analysis requirements through the established NERC governance as suggested, but subsequent conversation with FERC staff led to the conclusion that requirements in PRC-009-0, an existing FERC approved standard which will be retired with the adoption and regulatory approval of PRC-006-1, cannot simply be dropped. As a result, the SDT found it necessary to include the event analysis requirements of PRC-009 as described in R11 and R13.

Voter	Entity	Segment	Vote	Comment
Bruce Krawczyk	ComEd	3	Negative	There remains confusion about multiple Planning Coordinators with potentially different criteria enforcing differing mitigations within postulated islands that may overlap amongst any number of PCs. WECC made this same argument and was subsequently granted a separate set of Requirements to alleviate this confusion. It doesn't seem fair that the Eastern Interconnection wouldn't also be able to enjoy that same degree of certainty and ability to adequately plan. **Response**: The WECC Variance was added in response to a specific request from the WECC entities. The SDT notes however, that in general industry comments raised significant concerns with the compliance implications of forcing entities to reach agreement. The SDT acknowledges that if a Distribution Provider's area is covered by more than one Planning Coordinator, it is possible for the Distribution Providers to be required to adhere to different programs in different parts of its area. This is most likely to occur when a Distribution Provider area includes portions of more than one region. Should this situation occur, the process defined in Requirement R14 allows for UFLS Entities to provide input to the Planning Coordinators regarding the impact of proposed UFLS program modifications. Exelon's previously stated concern that there is not a requirement that all load participate equally in maintaining frequency has not been addressed. **Response**: The SDT continues to believe that this is a detail best addressed during the UFLS program design. There is a lot of confusion about the interaction of generation with load regarding this frequency standard. This standard states that there is no applicability to generation owners or operators, yet the PCs are required to obtain data from GOs. There is also a V/Hz requirement that seems to apply to generators although it is not specifically stated as such. **Response**: The Planning Coordinators are not required to model the generator underfrequency and overfrequency trip points until PRC-024 is approved, after which time the data will become available. The V/Hz requirement is a requirement on the Planning Coordinator to assess V/Hz condition in simulations and does not place any requirements on the Generator Owner, nor does it require the Planning Coordinator to obtain any data from the Generator Owner. There needs to be coordination between load and generation to maintain frequency across an interconnection or within an island and that cooperation is not addressed in this standard. There may be another standard in development that applies to

Voter	Entity	Segment	Vote	Comment
				generation addressing some or all of the elements to maintain frequency and perform adequate studies, but that should not be assumed to be the case in the development of an enforceable standard. There is confusion regarding Exhibit 1 and how the generator curve requirements and load shape requirements are to be mapped into future requirements. **Response**: The coordination between load and generation is being achieved through the coordination of standards PRC-006 and PRC-024. The UFLS SDT and the Generator Verification SDT have coordinated the requirements in the two standards to achieve the necessary reliability objective that generator tipping will not impinge on UFLS program effectiveness. Following the previous ballot the SDT added annotation to Attachment 1 to clarify application of the curves Islanding criteria should be consistent and developed through a standards process that allows development through a stakeholder process. This proposed standard circumvents the NERC process and requires PCs to unilaterally impose criteria without sufficient guidance or feedback. There should be a single set of criteria for the determination of an island, which is consistent across the interconnection, unless a specific geographic or regional exception is identified. The standard should state that even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint. **Response**: The SDT believes that due to differences in physical system characteristics between regions, issues such as how islands are identified are best left to the Planning Coordinators. Comments received during development of the standard indicate industry support for this approach. It is certain that there are many valid approaches to criteria for island identification and any one may be as good as another. A single set of criteria is not appropriate. The standard only requires that Planning Coordinators establish criteria to identify islands for the purpose of conducting their UFLS design assessments, thus the Planning Coordinators will not be unilaterally imposing criteria on other entities. The SDT believes the standard already provides each Planning Coordinator with sole responsibility for developing island identification criteria for its area, although to provide coordination of UFLS programs, a Planning Coordinator may be required to assess an island identified through application of an adjacent Planning Coordinator's criteria in an and adjacent area. There should be some recognition in the standard that UFLS schemes currently exist and effort should be made to avoid needlessly changing relays or settings on

Voter	Entity	Segment	Vote	Comment
				many thousands of installations if some arbitrary and common set points were to be determined by the PC, thus causing needless expense. It is likely desirable to have slightly different settings for UFLS across a footprint so as to not create load changes that are too abrupt. **Response**: The SDT agrees that arbitrary changes to UFLS programs could result in needless effort and expense. The SDT expects that Planning Coordinators will not be developing modifications to UFLS programs unless an Assessment pursuant to Requirement R4 identifies deficiencies that prevent meeting the performance characteristics in Requirement R3. The process defined in Requirement R14 allows for UFLS Entities to provide input to the Planning Coordinators regarding the impact of proposed UFLS program modifications.
David A. Lapinski David Frank Ronk James B Lewis	Consumers Energy	3 4 5	Affirmative	While we recognize that changes to R2 of EOP-003-2 are not within the scope of the SAR, we are of the opinion that R2 needs significant revision. The vague concept of "Shall establish plans..." could be satisfied by a document that says that UVLS shall be installed by January 1, 2052. It is a plan, but probably not a very good one. R2 seems to establish no requirement for a good plan, no requirement that a plan be implemented, etc. If it is possible for the PRC-006-1 SDT to pass along this comment to the SDT working on EOP-003, it would be appreciated.
Response: Thank you for your comments and support. The SDT that is working on revising EOP-003 will be posting the proposed revisions to EOP-003 at a future date. You will have an opportunity at that time to provide your comments on EOP-003.				
Henry Ernst-Jr	Duke Energy Carolina	3	Affirmative	There is a typographical error on the “High” VSL for EOP-003-2 Requirement R3. The phrase “or less” after 15% should be struck.
Response: Thank you for your support. The proposed change is outside the scope of the supplemental SAR for this project to revise the requirements specific to Underfrequency Load Shedding in EOP-003-1 to remove inconsistencies and redundancies with PRC-006-1. The SDT suggests that the commenter submit this concern to the team working on project 2009-03.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	Curves rather than a table results in unrealistic compliance expectations.
Response: The SDT converted the performance characteristics for frequency-time limits from tabular format to curves in response to industry comments. The SDT also has added the equations in tabular format that define the curves in order to address compliance concerns associated with the lack of precision associated with reading values off the graph. The SDT believes that providing the requirement in both tabular and graphical format should address any compliance concerns related to the curves.				

Voter	Entity	Segment	Vote	Comment
James R. Keller Anthony Jankowski Linda Horn	Wisconsin Electric Power Marketing Wisconsin Energy Corp Wisconsin Electric Power Co.	3 4 5	Negative	During the 9/17/10 Webinar we commented that our company, as a DP, is covered by two Planning Coordinators. Other entities also indicated a similar situation during the Webinar. In response, the SDT stated that this situation was not taken into consideration and further commented that this situation appears to be a registration issue. The reality is this situation exists and the standard as written does not have a strong enough mechanism to prevent two or more Planning Coordinators from designing respective UFLS programs with conflicting settings for the UFLS Entity that the two Planning Coordinators cover. **Response**: Two overlapping Planning Coordinators was not intended when the function was defined; however, because of the registration these scenarios exist. The SDT does not believe the standard should be adjusted since the tasks assigned to the Planning Coordinator align with the existing definition and tasks aligned with this entity in the current version of the Functional Model. If the case of two overlapping Planning Coordinators persists, it should behoove them to coordinate their designs in such fashion that a DP is not presented with a situation in which it is impossible to achieve compliance. The Planning Coordinator coordination in Requirement R5 appears to be the standard's main method for attempting to prevent conflicting UFLS program designs. However, the sub-bullets in R5 are a choice of three options, the last of which does not force a resolution of Planning Coordinators' differences. The first two sub-bullets should not be choices, but required actions. The last sub-bullet needs to be removed as it does not force a resolution when there are conflicts/differences in UFLS program designs. R13 should be revised to follow this same concept. **Response**: During development of this standard the industry comments raised significant concerns with the compliance implications of forcing entities to reach agreement. The SDT agrees that the first two bullets in Requirements R5 and R13 are preferable methods for demonstrating compliance. However, the SDT also believes that the third bullet provides Planning Coordinators a necessary method to comply without reliance on other entities and the SDT expects providing recommendations to the other Planning Coordinators and the ERO will lead to resolution of issues. In response to comments and during the Webinar, the SDT stated that it anticipates the assumption of burden by UFLS Entities for generators that do not conform to the PRC-024 underfrequency/overfrequency tripping curves will not be significant. We continue to believe that ignoring generator responsibilities due to possible small

Voter	Entity	Segment	Vote	Comment
				burden is not acceptable, as in some areas the burden may be significant and unwarranted without an obligation on the generator. Since the standard requires the study of the effects of non-conforming generators, the SDT must feel that the effects of non-conforming generators may be significant. **Response**: The PRC-024-1 curves were chosen in view of permissible off-nominal frequency time durations advised by major generator manufacturers and in view of existing regional guidelines on generator off-nominal frequency protection. The team's expectation, therefore, is that the amount of non-conforming generation will be small. Some regions currently have generator under-frequency tripping characteristic guidelines that are of higher frequency and of shorter time delay than the PRC-024-1 Attachment 1 curve allowing generators to trip sooner or at higher frequencies. We expect that this may initially produce a significant quantity of non-conforming generators in some regions due to the settings of under-frequency relays, but that there should generally be no particular technical reason for not resetting these relays to conform to the PRC-024-1 Attachment 1 curves once that standard becomes enforceable. The continent-wide standard does not prevent regional standards from requiring compensatory load shedding by Generator Owners thus shifting the burden of responsibility. It is for the above reasons that we continue to believe that the UFLS program which is ultimately implemented by the UFLS Entity needs to be mutually agreed to between the Planning Coordinator and the UFLS entity. **Response**: Requiring mutual agreement or concurrence between entities was found to be unacceptable by many industry commenters due to one entity's compliance being dependent on what another entity does. Industry comments have supported that the Planning Coordinator is the correct Functional Model entity to develop the UFLS program based on its wide-area view and expertise in the studies necessary to assess UFLS program performance. The SDT also agrees that the UFLS Entities should have input into the process and has added Requirement R14 to address this concern.
Michael Ibold Liam Noailles David F. Lemmons	Xcel Energy, Inc.	3 5 6	Negative	Xcel Energy continues to believe that Generators Owners should be subject to this standard. The role of Generator response to under frequency conditions is integral to under frequency plan performance. Comments to previous responses indicate that a pending PRC-024, applicable to GOs, would resolve many of these concerns however the gap should be closed in this standard (PRC-006) until the PRC-024 standard is approved.

Voter	Entity	Segment	Vote	Comment
Response: In view of the scope of PRC-024 and the already established coordination between it and PRC-006, the SDT does not wish to introduce double jeopardy for Generator Owners. Filling the gap until PRC-024 is approved would lead to confusion regarding development of the same requirement in two standards, would be inefficient, cause extra complexity, and likely take longer than the time frame for approval of PRC-024.				
James A Ziebarth	Y-W Electric Association, Inc.	4	Negative	Y-WEA appreciates the efforts of the SDT in respect to addressing previous comments calling for region-wide UFLS program development. However, Y-WEA concurs with Tri-State G&T in believing that the duties performed by the Planning Coordinator under this proposed standard would be more appropriately carried out by the Reliability Assurer. In addition, the SDT's addition of R14 to the proposed standard is helpful in requiring that the parties developing UFLS programs respond to comments by the UFLS entities, but there is presently no requirement for the UFLS developers to solicit comments from the UFLS entities. For this reason, Y-WEA proposes that R14 be replaced with the following: R14. Each Planning Coordinator shall conduct a comment period before finalizing its UFLS program and shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following the comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following [VRF: Lower][Time Horizon: Long-term Planning]: 14.1. UFLS program, including a schedule for implementation 14.2. UFLS design assessment 14.3. Format and schedule of UFLS data submittal
Response: The SDT believes that the WECC variance specifically addresses this concern by requiring a single coordinated program in the WECC interconnection. The Planning Coordinators will need to work together on this coordinated, region-wide program. The SDT believes the Planning Coordinator is still the appropriate entity to perform this function.				
Michael J. Haynes	Seattle City Light	5	Affirmative	Rationale: SCL SME concur with WECC's recommendation to approve both proposed PRC-006-1 - Automatic Underfrequency Load Shedding and EOP-003-2 - Load Shedding Plans. Proposed PRC-006 includes a Regional Variance for the Western Interconnection that requires Planning Coordinators to continue regional coordination for Underfrequency Load Shedding Plans, an element missing from the PRC-006 standard balloted in July 2010. Proposed EOP-003-2 removes automatic Uunderfrequency Load Shedding requirements from EOP-003-2, as they are redundant with PRC-006-1, and to remove from the Balancing Authority requirements for which they are not responsible.
Response: Thank you for your comments and support of the standard.				
Jim D.	JDRJC	8	Negative	Too many administrative requirements and overly complex

Voter	Entity	Segment	Vote	Comment
Cyrulewski	Associates			
Response: The SDT cannot fully consider the comment without additional detail. However, the SDT believes the approach taken provides the Planning Coordinators the greatest flexibility by defining what performance characteristics the UFLS program must meet to support system reliability rather than defining how the Planning Coordinators are to design the UFLS program.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	NPCC supports the standard however some reservation exists about a potential "fill in the blank" nature of the requirements. The PC is required to have a UFLS program and this program is required to be followed by the TOs and GOs even though FERC has not seen the specific program. There are targets specified in the standard that a PC must meet however it should be recognized that there are many different potential programs that may meet the target and contain other concerns. It would have been more desirable to have only the basic program targets for the PCs to have in their individual programs in this standard and then, in the companion Regional Standards that the ERO already directed the regions to develop, Have the specific PC program requirements and the specific requirements on the TOs and GOs to follow them. As written currently, the standard requires the TOs and GOs to follow some unapproved and not commission filed program. Compliance with this may be problematic.
Response: Many regions are developing regional standards or have regional criteria that establish the region's UFLS program requirements. The PC is required to notify the UFLS entities of the UFLS program requirements and schedule for implementation as required in Requirement R3. The UFLS entities will know what is expected and when. The SDT recognized that because the characteristics and UFLS needs of regions are different, establishing one UFLS program is unrealistic; however, the standard does propose common performance characteristics that all UFLS programs must meet. This promotes consistency for the benefit of reliability across UFLS programs while not prescribing one program that would excessively restrict regions from designing UFLS programs that best fulfill their needs.				

Exhibit E — Standard Drafting Team Roster

Under Frequency Load Shedding Standard Drafting Team (Project 2007-01)

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Exhibit F — Record of Development of Proposed Reliability Standards

Project 2007-01
Underfrequency Load Shedding

Related Files

Status:
Approved by the Board of Trustees on November 4, 2010.

Purpose / Industry Need:
PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs

PRC-007 — Assuring Consistency with Regional UFLS Programs

PRC-009 — UFLS Performance Following an Underfrequency Event

The purpose of revising the above standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems – ensure each of the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties - the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Incorporate other general improvements described in NERC's Reliability Standards Development Plan: 2007-2009 (summarized and outlined in the Reliability Standard Review Guidelines attached as Appendix A).
4. Consider the items mentioned in the Standard Review Forms (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) attached as Appendix B, prepared by the NERC staff, which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006),
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,
    - Version 0 standards development (see note 1), and
    - Regional Fill-in-the-Blank Team (RRSWG — a NERC working group involved with regional standards development).

   The standard drafting team should also consider any other issues that were not completely captured but were stated or referenced in the above materials.
5. Consider issues raised by the industry during the posting of the SAR for Project 2007-01 during the first comment period from November 29, 2006 through January 12, 2007, attached as Appendix C
6. Satisfy the standards procedure requirement for five-year review of the standards.

Draft	Action	Dates	Results	Consideration of Comments
Draft 6 PRC-006-1 Clean(80) | Redline to Last Ballot(81) EOP-003-2 Clean(78) | Redline to Last Approval(79) Implementation Plan Clean(77) **Supporting Materials** Last approved version of standards absorbed into PRC-006-1: PRC-006-0 (76)—Development and Documentation of Regional UFLS Programs PRC-007-0 (75)—Assuring Consistency with Regional UFLS Program Requirements PRC-009-0 (74)—UFLS Performance Following an Underfrequency Event	Recirculation Ballot Info(82) Vote>>	October 18-28, 2010 (closed)	Summary(84) Full Record (83)	
Draft 5 PRC-006-1 Clean(65) | Redline	Successive Ballot and Non-binding VRF/VSL Poll	09/24/10 - 10/04/10 (closed)	Summary(71)	Consideration of Comments(73)

to Last Ballot(66) EOP-003-2 Clean(63) | Redline to Last Ballot(64) Implementation Plan Clean (61)| Redline to Last Ballot(62) **Supporting Materials:** VRF/VSL Justification(60) Justification for Quebec Variance(59) Justification for WECC Variance(58)	Vote>> Info(68) Info_Extension(67)		Full Record(70) Non-binding Poll Results(69)	Consideration of Poll Opinions(72)
Draft 4 Underfrequency Load Shedding Program Requirements and Proposed Continent-wide Standard PRC-006-1 Clean(52) | Redline to Initial Ballot(53) EOP-003-1 Clean(50) | Redline to Initial Ballot(51) Implementation Plan Clean(48) | Redline to Initial Ballot(49)	Second Ballot Vote>> | Info(54)	07/24/10 - 08/03/10 (closed)	Summary(56) Full Record(55)	Consideration of Comments(57)
Draft 3 Underfrequency Load Shedding Program Requirements and Proposed Continent-wide Standard PRC-006-1	Initial Ballot and Non-binding VRF/VSL Poll Vote>> | Info(40)	07/08/10 - 07/17/10 (closed)	Full Record(44) Non-binding Poll Results(43) Summary(42)	Consideration of Comments(47) Consideration of Poll Opinions(46)
	Pre-ballot Review	06/11/10 -		

Clean(36) | Redline to last posting(37) EOP-003-1 Clean(34) | Redline(35) Implementation Plan Clean(32) | Redline(33) **Supporting Materials:** Comment Form (Word)(31) Review of FERC Issues from Database(30) Supplemental SAR(29)	Join>> | Info(39)	07/02/10 (closed)		
	Comment Period Submit Comments>> Info(38)	06/11/10 - 07/16/10 (closed)	Comments Received(41)	Consideration of Comments(45)
Draft 2 Underfrequency Load Shedding Program Requirements and Proposed Continent-wide Standard PRC-006-1(25) **Supporting Materials:** Comment Form (Word)(24) Mapping Document(23)	Comment Period Info(26) Submit Comments>>	04/21/09 - 05/21/09 (closed)	Comments Received(27)	Consideration of Comments(28)
Draft 1 Underfrequency Load Shedding Regional Reliability Standards Characteristics	Comment Period Info(20) Submit Comments>>	07/02/08 – 08/15/08 (closed)	Comments Received(21)	Consideration of Comments(22)

Draft 1 UFLS Characteristics **(19)** **Supporting Materials:** Comment Form (Word) **(18)** Implementation Plan**(17)**				
Draft 3 Draft SAR Version 3 Clean**(13)** | Redline from last posting**(14)**	Standard Drafting Team Nominations Info**(16)** **(15)** Nomination>>	03/15/07 – 03/29/07 (closed)		
Draft 2 Underfrequency Load Shedding Draft SAR Version 2 (Revised) Clean**(7)** | Redline from 1st posting**(8)**	Comment Period Info**(10)** Submit Comments**(9)**	02/08/07 – 03/09/07 (closed)	Comments Received**(11)**	Consideration of Comments**(12)**
Draft 1 Underfrequency Load Shedding Posted for 30-day Comment Period Draft SAR Version 1**(1)**	Comment Period SAR Drafting Team Nominations Info>>**(4)** Submit Comments **(3)** Submit Nominations**(2)**	11/29/06 – 01/12/07 (closed) Comment Period 11/29/06 – 12/12/06 (closed) Nomination Period	Comments Received**(5)**	Consideration of Comments**(6)**

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Standard Authorization Request Form

Title of Proposed Standard	Underfrequency Load Shedding (UFLS) Standards Project 2007-01
Request Date	November 14, 2006

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Regional Reliability Standards Working Group	☐	New Standard
Primary Contact	Robert W. Millard Director of Standards ReliabilityFirst Corporation	☒	Revision to existing Standards PRC-006, PRC-007, PRC-008, and PRC-009
Telephone Fax	(630) 261-2621 (630) 691-4222	☐	Withdrawal of existing Standard
E-mail	bob.millard@rfirst.org	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

PRC-006— Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-008 — Underfrequency Load Shedding Equipment Maintenance Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

The purpose of revising the above four standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems - the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties - the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Incorporate other general improvements described in the standards development work plan.
4. Consider comments received during the initial development of the standards and other comments received from ERO regulatory authorities and stakeholders, as noted in the attached review sheets.
5. Satisfy the standards procedure requirement for five-year review of the standards.

Industry Need (**Provide** a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

The four standards in this set are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to stand up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team will work with stakeholders to review PRC-006 and each of the current regional UFLS procedures to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 through PRC-009 have some 'fill-in-the-blank' characteristics as identified in the Regional Reliability Standards Working Group work plan which need to be removed.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest Reliability Authority.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☐	Planning Authority	Plans the Bulk Electric System.
☐	Resource Planner	Develops a long-term (>one year) plan for the resource adequacy of specific loads within a Planning Authority area.
☐	Transmission Planner	Develops a long-term (>one year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☒	Transmission Owner	Owns transmission facilities.
☒	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders.
☒	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer.
☐	Generator Owner	Owns and maintains generation unit(s).
☐	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity, and all necessary Interconnected Operations Services as required.
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☒	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-006-0**	**Comments**
Title	Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs	Too long – slight difference with header.
Purpose		Implement vs. develop & document. Underfrequency spelled differently.
Applicability		RRO not in FM.
Requirements	*Conditions*	Okay
	Who?	R1.1 – includes sub-regions.
	Shall do what?	R1.3 – define sufficient; model at RRO or others or both? R1.4.2 – check grammar and capitalization; loosely worded. R2 & 3 – format of documentation.
	Result or Outcome	Missing
Measures		No real measures and definition of evidence required.
To Do List	FERC NOPR o Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information. (see recommendations for improvement) FERC staff report o Concern with Blackout items (especially #21) o Fill in the blank o Definition of RRO as user of system o Lack of coordination Regional Fill-in-the-Blank Team Comments o Modify R1 to require each Region to develop a regional standard, and o Determine what elements (if any) of UFLS should be included in the North American standard and what elements should be included in the regional standards. o Development of regional standards needs to be coordinated with Regional entities. Regional entities should begin process for developing regional standards once the drafting team for the North American standard has determined what elements of UFLS should be included in the continent-wide standard and what elements should be included in the regional standards. o PRC-006 will be a continent-wide standard supported by Regional Reliability Standards. o Related PRC-007, PRC-008, and 009. V0 Industry Comments o Not a standalone standard o Who do you submit compliance material to? o Need to define evidence	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-007-0**	**Comments**
Title	Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organizations' Underfrequency Load Shedding Program Requirements	Too long and different than header.
Purpose		Same as 006 and doesn't address 007. No value proposition or benefit. Spelling of Underfrequency.
Applicability		Okay
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	R1 – what about coordination? R2 – provide format, etc. and define 'as necessary'.
	Result or Outcome	Missing
Measures		2 M for 3 R. M1 – define consistency M2 – define evidence
To Do List	FERC NOPR o No changes identified. Regional Fill-in-the-Blank Team Comments o Change "program" to "standard" in R1. o Coordinated with PRC-006. o The regional procedures need to be converted to a standard to implement this. V0 Industry Comments o Need to include RA o Need to refine levels of non-compliance	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-008-0**	**Comments**
Title	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	Too long and different than header. Doesn't cover testing element.
Purpose		Same statement that has been carried forward and doesn't fit here. No benefit or value proposition.
Applicability		Okay
Requirements	*Conditions*	Not clear how this differs from 005.
	Who?	Okay
	Shall do what?	R2 – format, etc. missing.
	Result or Outcome	Missing
Measures		M2 needs to define evidence.
To Do List	FERC NOPR o Include a requirement that maintenance and testing of UFLS programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System. FERC staff report o Maintenance intervals not addressed Regional Fill-in-the-Blank Team Comments o Okay if PRC-006 is fixed V0 Industry Comments o Consistent wording from standard to standard required o Definition of evidence required	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-009-0**	**Comments**
Title	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	Too long and different than header.
Purpose		Same as previous and it doesn't fit. No benefit or value proposition.
Applicability		Okay
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	Okay
	Result or Outcome	Missing
Measures		M1 not really a measure. M2 needs definition of evidence.
To Do List	FERC NOPR o No changes identified. FERC staff report o No corresponding standard for under-voltage Regional Fill-in-the-Blank Team Comments o Change "program" to "standard'. o See notes for PRC-007. V0 Industry Comments o Define evidence o 90 days vs. 30 days o Exemptions for those with shunt reactors who don't shed load	

Nomination Form — Underfrequency Load Shedding SAR Drafting Team

Please return this form to sarcomm@nerc.com by **December 12, 2006**. For questions, please contact Richard Schneider at 609-452-8060 or richard.schneider@nerc.net

Please note this drafting team will likely meet initially the week of January 22, 2007 in Austin, Texas.

Name: Organization: Address: Office Telephone: E-mail:
Please briefly describe your experience and qualifications to serve on the Underfrequency Load Shedding SAR Drafting Team. Prefer experience in developing load shedding plans, in specifying criteria for load shedding plans, in testing load shedding plans, in developing load shedding equipment maintenance programs, or in analyzing load shedding events. Previous experience working on or applying NERC or IEEE standards is beneficial, but not a requirement.

I represent the following NERC Reliability Region(s) (check all that apply):	**I represent the following Industry Segment (check one):**	
☐ ERCOT	☐	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities

☐ RFC ☐ SERC ☐ SPP ☐ WECC ☐ NA – Not Applicable	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations and Regional Entities

Which of the following Function(s)[1] do you have expertise or responsibilities:

☐ Reliability Coordinator	☐ Transmission Service Provider
☐ Balancing Authority	☐ Transmission Owner
☐ Interchange Authority	☐ Load Serving Entity
☐ Planning Authority	☐ Distribution Provider
☐ Transmission Operator	☐ Purchasing-selling Entity
☐ Generator Operator	☐ Generator Owner
☐ Transmission Planner	☐ Resource Planner
	☐ Market Operator

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.

Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

[1] These functions are defined in the NERC Glossary of Terms, which is downloadable from the NERC Web site.

Comment Form — 1st Draft of SAR for Underfrequency Load Shedding

Please use this form to submit comments on the proposed SAR for Underfrequency Load Shedding (UFLS). Comments must be submitted by **January 12, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the abbreviation "UFLS" in the subject line. If you have questions please contact David Taylor at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs, ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following four standards:

PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-008 — Underfrequency Load Shedding Equipment Maintenance Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

The four standards associated with this project are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team will work with stakeholders to review PRC-006 and each of the current regional UFLS procedures to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☐ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments:

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments:

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments:

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731
www.nerc.com • 609-452-8060 (Voice) • 609-452-9550 (Fax)

November 29, 2006

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement
Comment Period Opens for UFLS SAR; Nomination Period Opens for UFLS SAR Drafting Team

The Standards Committee announces the following standards actions:

Underfrequency Load Shedding Standards Authorization Request (SAR) (November 29, 2006–January 12, 2007)

A new SAR, Underfrequency Load Shedding, has been posted for a 30-day comment period from November 29, 2006 through January 12, 2007, which includes extra days to account for holiday weekdays. The SAR will update the following standards:

PRC-006-0 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007-0 — Assuring Consistency with Regional UFLS Programs
PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs
PRC-009-0 — UFLS Performance Following an Underfrequency Event

The SAR is project 2007-01 in the Reliability Standards Work Plan: 2007–2009. This project involves upgrading the overall quality of these four standards; eliminating gaps in the requirements; eliminating ambiguity; and eliminating "fill-in-the-blank" components.

The development of these standards may include other improvements deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

Please use the SAR comment form to provide comments.

Nominations for Underfrequency Load Shedding SAR Drafting Team (November 29–December 12, 2006)

The Standards Committee is seeking industry experts to serve on the Underfrequency Load Shedding SAR Drafting Team. If you are interested in serving on this team, please complete this nomination form and return it to Richard Schneider (Richard.schneider@nerc.net) no later than December 12, 2006.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

Standards Process Manager

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Comment Form — 1st Draft of SAR for Underfrequency Load Shedding

Please use this form to submit comments on the proposed SAR for Underfrequency Load Shedding (UFLS). Comments must be submitted by **January 12, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the abbreviation "UFLS" in the subject line. If you have questions please contact David Taylor at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Anthony Jablonski	
Organization:	ReliabilityFirst Corporation	
Telephone:	(630) 378-5717	
E-mail:	anthony.jablonski@rfirst.org	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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This project involves revising the requirements in the following four standards:

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The four standards associated with this project are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

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The standard drafting team will work with stakeholders to review PRC-006 and each of the current regional UFLS procedures to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments:

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: See attached file 'SAR-Comment_Form_2007-01_UFLS_29Nov06_Attachment'

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☒ No

   Comments:

ATTACHMENT TO

"SAR Comment Form 2007-01 UFLS 29Nov06"

Submitted 12/14/06 by:

Anthony Jablonski
ReliabilityFirst Corporation
Standards Department
(630) 378-5717
anthony.jablonski@rfirst.org

Comment regarding acceptability of the scope of project:

Inclusion of PRC-008, Maintenance and Testing, is not in the best interest of the development of the project or implementation of the project. Although PRC-008 does refer to the specific "relay system" known as UFLS, it more characteristic of the general subject area of "relay systems" which include:

PRC-008-0 Underfrequency Load Shedding Equipment
PRC-005-1 Transmission and Generator Protection System
PRC-011-0 UVLS System
PRC-017-0 Special Protection System

Typically companies develop maintenance and testing programs that cover all types of "relay systems". Compliance to these four standards is usually checked from the same source reference. PRC-008 is independent of the analysis and implementation of an UFLS program. Project 2007-01 should only include PRC-006, 007 and 009.

Comment Form — 1st Draft of SAR for Underfrequency Load Shedding

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Steve Myers	
Organization:	ERCOT	
Telephone:	512-248-3077	
E-mail:	smyers@ercot.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs, ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: It is important for clear requirements to exist that meet the technical intent of the operations of UFLS as part of defense-in-depth to ensure the reliability of the BES. Because there are many different arrangements, organizational and contractual, among the various Regions, the standards must state the technical requirements that must be met ("what") and not prescribe "how".

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments:

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☒ No

   Comments: In concert with the stated process, I do not believe it would be appropriate to go beyond what has been stated. Once these items have been "cleaned up", additional standards revisions may be proposed to address other concerns…using the standards revision process.

Comment Form — 1st Draft of SAR for Underfrequency Load Shedding

Please use this form to submit comments on the proposed SAR for Underfrequency Load Shedding (UFLS). Comments must be submitted by **January 12, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the abbreviation "UFLS" in the subject line. If you have questions please contact David Taylor at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
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	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: SERC EC Planning Standards Subcommittee

Lead Contact: **Travis Sykes**

Contact Organization: **Tennessee Valley Authority**

Contact Segment: **1**

Contact Telephone: **423-751-4162**

Contact E-mail: **tssykes@tva.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Darrell Pace	Alabama Electric Coooperative	SERC	1
Bob McGarrah	Ameren	SERC	1
Brian Moss	Duke Energy Carolinas	SERC	1
David Weekley	MEAG Power	SERC	1
Pat Huntley	SERC Reliability Corp	SERC	10
Phil Kleckley	SC Electric and Gas	SERC	3
Bob Jones	Southern Company Services, Inc.	SERC	1

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following four standards:

PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
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PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

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PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: This seems to be a standard where fill-in-the-blank in the form of regional standards are needed.

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: The scope is not clearly defined. It is not clear how the items on pages 6 through 9 are to be incorporated. The items on these pages should be items for consideration by the SDT, but they are not necessarily required to be in the standard.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Andrew Fusco	
Organization:	NCMPA1	
Telephone:	919-760-6219	
E-mail:	afusco@electricities.org	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
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	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments:

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: See attached file. I could not get comment field to extend past one line.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: See attached file. I could not get comment field to extend past one line.

NCMPA1 Comment on Question #2:

NCMPA1 agrees with the need to develop measures to shed load during an underfrequency event that are consistent across the interconnected electric system. However, NCMPA1 disagrees with the approach that has been taken by the regions in responding to this requirement, and we are concerned that the same approach is suggested in this SAR. We are specifically concerned that it is simply not practical for smaller entities to comply with the requirements proposed by this SAR.

As a result of the Energy Policy Act, many small utilities are required to register with their respective RROs, and these entities are now subject to mandatory compliance with the reliability standards. Some of these entities have peak annual loads that are smaller than 10 MW. Some are even smaller than 1 MW. Requirements within most, if not all, of the regions state that load must be shed in multiple steps (three steps in SERC, for example) at different underfrequency set points. While shedding load in multiple steps is perfectly rational for larger systems, most small loads are served by one distribution feeder bus. Furthermore, the entire peak demand on a small entity is a mere fraction of the amount of load that is shed by a larger entity in just one step. Furthermore, larger utilities have the advantage of aggregating load from multiple delivery points that can be shed in one step. Smaller entities do not have this advantage, and face the possibility of large expenditures in order to meet the multiple step shedding criteria.

NCMPA1 questions the benefit to reliability by requiring all utilities, regardless of size, to shed load in multiple steps as a result of an underfrequency event. We urge the SAR/standard drafting teams to address this issue and establish simplified requirements for small entities, whereby,

- Compliance with the UFLS standards be non-compulsory for entities with annual peak demands less than 10 MW
- Load shedding can be carried out in one step for entities with annual peak demands less than 100 MW.

NCMPA1 Comment on Question #3

The top margin on pages SAR 5 through SAR 9 says “System Restoration and Blackstart”. This appears to be some sort of editing mistake, and we recommend that it be changed to “Underfrequency Load Shedding”.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Brian Thumm	
Organization:	ITC Transmission	
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E-mail:	bthumm@itctransco.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
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Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: While some improvement is probably necessary, it is not clear how removing "fill in the blank" characteristics will benefit reliability. Some Reliability Standards, such as the UFLS Standards, can benefit from a Regional coordination effort. Regional coordination in this case is preferred over an Interconnection-wide coordination effort.

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: SARs are supposed to clearly identify the scope of the proposed standard. SARS are intended to meet a specific industry need. This SAR appears to be a laundry-list garnered from various sources and ideas on what might be put in a standard. The scope of the proposed standard is not adequately addressed.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Ed Davis	
Organization:	Entergy Services, Inc.	
Telephone:	504-576-3029	
E-mail:	edavis@entergy.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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   ☐ Yes

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   Comments:

   This seems to be a standard where fill-in-the-blank in the form of regional standards are needed.

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   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments:

   The scope is not clearly defined. It is not clear how the items on pages 6 through 9 are to be incorporated. The items on these pages should be items for consideration by the SDT, but they are not necessarily required to be in the standard.

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   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Ron Falsetti	
Organization:	IESO	
Telephone:	905-855-6187	
E-mail:	ron.falsetti@ieso.ca	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs, ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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   ☒ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments: We agree with the general scope; however, we have concerns over the comments provided in the 4 tables. In fact, we question whether or not it is appropriate to include these tables in the SAR as they are not part of the appendices of the approved Reliability Standards Development Procedure (RSDP).

   Page 14 (Version 6.0) of the RSDP clearly states that the objective as: A valid SAR that clearly justifies the purpose and describes the scope of the proposed standard action and conforms to the requirements of a SAR outlined in Appendix A.

   It seems to us that this SAR has gone beyond the bound of established standard procedure.

   These comments do not represent the majority view of the industry as we believe they have not been reviewed and commented by industry participants. Hence, these comments can at best be regarded as views of the person or group that prepared the table. But by being included in the SAR, these comments may mislead or restrict the thinking of the Standard Drafting Team in developing the revised standards.

   We support moving forward with the standard development work according to the scope provided in the SAR, but urge the Standard Drafting Team to regard these comments as personal views only that should be forwarded through the normal SAR commenting process. We also recommend that all future SAR writers not to use materials (the table, in this case) that are not part of the approved RSDP.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☒ No

   Comments:

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Organization:		
Telephone:		
E-mail:		
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☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name: **Midwest ISO Stakeholders Standards Collaboration Participants**

Lead Contact: **Jason Marshall**

Contact Organization: **Midwest ISO**

Contact Segment: **2**

Contact Telephone: **317-249-5494**

Contact E-mail: **jmarshall@midwestiso.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Jim Cyrulewski	JDRJC Associates	**RFC**	1
Brian F. Thumm	ITC	**RFC**	1
Greg Berg	Otter Tail Power	**MRO**	1
Terry Bilke	Midwest ISO	**RFC, MRO, SERC**	2

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   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: While some improvement is probably necessary, it is not clear how removing "fill in the blank" characteristics will benefit reliability. While there is merit in having some interconnection view with regard to the standards, to ensure coordinated performance, the Regions currently play an important role. There are areas that have unique requirements that may not be adequately addressed by a continent-wide or interconnection-wide approach. This role should filled primarily as TOs, TOPs, DPs, and LSEs with the region coordinating the activities.

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: SARs are supposed to clearly identify the scope of the proposed standard. SARS are intended to meet a specific industry need. This SAR appears to be a laundry-list garnered from various sources and ideas on what might be put in a standard.

   It's unclear to us who is the agent or entity responsible for determining the interconnections' setpoints and overseeing the transition to any new requirements. It's also unclear who is accountable if the settings and process aren't correct. However, we do believe the TOs, TOPs, DPs and LSEs should have the responsibility to determine these settings with the Regions coordinating the activities.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments: This does not appear to be a yes-no question.

One major change needed in all the standards is to separate the standard into two pieces. The first is the set of core reliability requirements. The second portion is the supporting text. More than half the text in the current standards is supporting text that explains the true requirements. Now NERC is in the process of developing measures for and assigning risk to sentences that were never intended to be measured.

Comment Form — 1st Draft of SAR for Underfrequency Load Shedding

Please use this form to submit comments on the proposed SAR for Underfrequency Load Shedding (UFLS). Comments must be submitted by **January 12, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the abbreviation "UFLS" in the subject line. If you have questions please contact David Taylor at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs, ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **IRC Standards Review Committee**

Lead Contact: **Charles Yeung**

Contact Organization: **SPP**

Contact Segment: **2**

Contact Telephone: **832-724-6142**

Contact E-mail: **cyeung@spp.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Alicia Daugherty	PJM	**RFC**	2
Mike Calimano	NYISO	**NPCC**	2
Ron Falsetti	IESO	**NPCC**	2
Matt Goldberg	ISO-NE	**NPCC**	2
Brent Kingsford	CAISO	**WECC**	2
Anita Lee	AESO	**WECC**	2
Steve Myers	ERCOT	**ERCOT**	2
Bill Phillips	MISO	**RFC / SERC**	2

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following four standards:

PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-008 — Underfrequency Load Shedding Equipment Maintenance Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

The four standards associated with this project are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team will work with stakeholders to review PRC-006 and each of the current regional UFLS procedures to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments:

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments: We agree with the general scope. However, the scope does not clearly state an important objective, for this and any standard revisions, that the end product should contain only the core reliability requirements without any guideline or procedure type of information. Further, we have concerns over the comments provided in the 4 tables. In fact, we question whether or not it is appropriate to include these tables in the SAR as they are not part of the appendices of the approved Reliability Standards Development Procedure (RSDP). It seems to us that this SAR has gone beyond the bound of established standard procedure.

   The comments in the Tables may not represent the majority view of the industry as we believe they have not been reviewed and commented by industry participants. Hence, these comments can at best be regarded as views of the person or group that prepared the table. But by being included in the SAR, these comments may mislead or restrict the thinking of the Standard Drafting Team in developing the revised standards.

   We ask the SAR Draft Team to please enlighten us on who provided these comments and how these comments got included in the SAR.

   We support moving forward with the standard development work according to the scope provided in the SAR, but urge the Standard Drafting Team to regard the comments in the Tables as personal views only that should be forwarded through the normal SAR commenting process. We also recommend that all future SAR writers not to use materials (the table, in this case) that are not part of the approved RSDP.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments:

Please take a closer look at the applicability of each of the standard requirements. We believe some of them may not cover all the responsible entities. For example:

a. PRC-007-0

TOP's & LSE's are missing from R1, R2 & M1.

b. PRC-008-0

TOP's & LSE's are missing from the Applicability, Requirements & Measures sections.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Jason Shaver	
Organization:	American Transmission Co.	
Telephone:	262 506 6885	
E-mail:	jshaver@atcllc.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team will work with stakeholders to review PRC-006 and each of the current regional UFLS procedures to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: ATC agrees that there is a reliability related need to upgrade this set of standards.

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: The Applicability section in each of these standards is unclear and must be clarified in the new standards.

   PRC-006

   We agree with the SAR Requestor that the Applicable section needs to be reassigned. With that being said the requestor did not provide the entity that should be responsible for these requirements. Failure to clearly identify, in the SAR, which entity is going to be assigned these requirements will make it difficult for the SDT to develop appropriate requirements.

   In assigning the appropriate entity the SAR drafting team needs to determine which entity has the authority or needs the authority to collect the data. ATC believes that there are only two options. The first is to assign the standard to the Regional Entities who has the authority to collect the data but is not subject to the FPA. The second option is to assign the standard to Planning Coordinators who are subject to the FPA but will need the authority to collect the data. Is this standard required to go through the formal standards development process if it is being assigned to Regional Entities?

   Once the SAR Drafting team determines the entity that will be assigned these requirements they must identify them in the "Reliability Function" section of the SAR.

   PRC-007, 008 and 009

   The SAR drafting team must review of the Applicability section in each of these standards. The SAR currently states that the Applicability is "okay" but we believe that additional clarity and reassignment of requirements is needed.

   ATC recommends that Balancing Authorities and Generator Owners be added to the list of potential entities that may be assigned either new or existing requirements.

ATC believes that any existing requirements assigned to the Transmission Operator should be reassigned to the appropriate entity. In addition, no new requirement should be assigned to the Transmission Operator.

The Applicability section identifies entities in the following manner:

'Entity Name" required by its Regional Reliability Organization to own a UFLS program.

The drafting teams should develop new language for identifying entities that are responsible for compliance with each standard.

3. Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.

☐ Yes

☐ No

Comments: The SAR fails to identity two existing standards that are related to this effort.

1) EOP-003-1 Load Shedding Plans. This standard will not be changed because of this work but the SDT should keep it in mind as they work on this set of standards.

2) PRC-005-1 Transmission and Generation Protection System Maintenance and Testing. This standard is identified in the review form for PRC-008-0 (page SAR-8). The SDT should consider if PRC-005 and PRC-008 could be combined into one single standard.

At a minimum both of these standards should appear in the Related Standards section of the SAR.

The SDT should also develop a new standard that addresses Generator Frequency Response. It's our opinion that Generator Frequency Response goes hand-in-hand with Under Frequency Load Shedding and therefore should be included in this set of standards.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	James H. Sorrels, Jr.	
Organization:	American Electric Power	
Telephone:	(614) 716-2370	
E-mail:	jhsorrels@.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☒ **RFC** ☐ **SERC** ☒ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
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	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☒	5 — Electric Generators
	☒	6 — Electricity Brokers, Aggregators, and Marketers
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	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments:

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments: We support the proposed scope with the following exceptions:

   We do not support the development of Regional Standards for UFLS. Each interconnection should have an UFLS standard requirement(s), and those requirements should be applied consistently throughout the interconnection. Regional variations in UFLS requirements should be only considered in very special situations, such as for FRCC within the Eastern Interconnection. Thus, the SAR scope should include the objective to eliminate the existing Regional variations that exist today and develop interconnection wide UFLS standards. The scope should still include the ability for entities to submit technical justification for why an area within an interconnection should have a separate UFLS Standard requirement that is different the rest of the interconnection. But, the SAR scope should not include the present objective of maintaining the content of PRC-006 which requires each Region to define their UFLS requirements.

   Additionally, we would request that the drafting team consider geographic dispersion of the underfrequency response load.

   Lastly, we would request that this SAR apply to all entities that have an impact on the bulk energy system.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: What is the technical basis of having varying Regional UFLS standards? Each Interconnection should have a consistent and coordinated UFLS standard requirement(s). Therefore, we support the development of Interconnection wide UFLS standards, not Regional standards within each interconnection, except for in situations that have technical justification to do otherwise.

We would also request clarity regarding compliance measures. Some requirements will lend themselves to plus or minus tolerances for a prescribed value, while others may be best described in terms of greater than or less than the prescribed value.

Additionally, Standard PRC-009 requires a simulation of the event (in addition to a description, a review of the set points and tripping times, and a summary of the findings). The time frame associated with providing documentation of the analysis, following the underfrequency event, is 90 calendar days (Requirement R2). Based on our experiences, we would request that the drafting team consider a longer time frame, such as 120 days.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	John E. Sullivan	
Organization:	Ameren	
Telephone:	(314) 554-3833	
E-mail:	JSullivan@ameren.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: There is no reason to eliminate the fill-in-the-blank form of the standards. We believe that each region should continue to develop, coordinate, and maintain their own UFLS programs.

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: The To Do Lists should be used as a guide to develop the scope of work for modifying these standards. However, these lists are not clear enough in themselves to constitute the scope of work for the Standard Drafting Team. These items should be considered by the Standard Drafting Team without necessarily requiring each item to become part of the reliability standards. The Standard need to include requirements for Generator Owners. (See comments under Item #3).

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: The standards need to be revised to include Generator Owners. In some cases generator owners want to set their underfrequency trip higher than regional requirements in order to conservatively protect their generating units. Presently the generator owners are not included in the Applicability section, therefore making enforcement of regional requirements difficult. The 'Apply to the Following Functions' section did not have Generator Owner as one of the entities selected, and the 'To Do List' also did not include this.

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Organization:		
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	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Midwest Reliability Organization

Lead Contact: **Dave Rudolph**

Contact Organization: **MRO for Group (Basin Electric for Contact)**

Contact Segment: **10**

Contact Telephone: **701.355.5722**

Contact E-mail: **drudolph@bepc.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Alan Boesch	NPPD	MRO	10
Terry Bilke	MISO	MRO	10
Robert Coish, Chair	MHEB	MRO	10
Carol Gerou	MP	MRO	10
Ken Goldsmith	ALT	MRO	10
Todd Gosnell	OPPD	MRO	10
Jim Maenner	WPS	MRO	10
Tom Mielnik	MEC	MRO	10
Pam Oreschnick	XEL	MRO	10
Dick Pursley	GRE	MRO	10
Eric Ruskamp	LES	MRO	10
Joe Knight, Secretary	MRO	MRO	10
27 Additional MRO Members	Not Named Above	MRO	10

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments:

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments: The MRO does NOT agree with the scope of the proposed project because the modification of these standards, PRC-006 through PRC-009, is a much more complex and detailed procedure than outlined in the scope.

   First, with FERC's recent announcement to remove the Regional Reliability Organizations (RRO's) from the Applicability section of ALL NERC standards, standard PRC-006 now needs to become a Regional Standard and be included in the Region's Delegation Agreement. Additionally, when a Regional Standard is developed for the UFLS program, the standard must enforce ALL member participation and that the UFLS study be customized and performed at a Regional level, not at a member level. The characteristics of each UFLS program may differ greatly between regions, thereby warranting a customized Regional Standard for each region.

   Finally, the MRO believes that the UFLS standards, PRC-007 through PRC-009 could be broadly applied to ALL entities that comply with a customized Regional UFLS standard. Therefore, for simplification purposes, the MRO would support combining standards PRC-007 through PRC-009 into one UFLS NERC standard.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☒ No

   Comments: The MRO does not have any additional comments at this time

Comment Form — 1st Draft of SAR for Underfrequency Load Shedding

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Kathleen Goodman	
Organization:	ISO New England	
Telephone:	(413) 535-4111	
E-mail:	kgoodman@iso-ne.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☒ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☒	2 — RTOs, ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following four standards:

PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-008 — Underfrequency Load Shedding Equipment Maintenance Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

The four standards associated with this project are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team will work with stakeholders to review PRC-006 and each of the current regional UFLS procedures to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments:

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments: We agree with the general scope. However, the scope does not clearly state an important objective, for this and any standard revisions, that the end product should contain only the core reliability requirements without any guideline or procedure type of information. Further, we have concerns over the comments provided in the 4 tables. In fact, we question whether or not it is appropriate to include these tables in the SAR as they are not part of the appendices of the approved Reliability Standards Development Procedure (RSDP). It seems to us that this SAR has gone beyond the bound of established standard procedure. These comments do not represent the majority view of the industry as we believe they have not been reviewed and commented by industry participants. Hence, these comments can at best be regarded as views of the person or group that prepared the table. But by being included in the SAR, these comments may mislead or restrict the thinking of the Standard Drafting Team in developing the revised standards.

   We support moving forward with the standard development work according to the scope provided in the SAR, but urge the Standard Drafting Team to regard these comments as personal views only that should be forwarded through the normal SAR commenting process. We also recommend that all future SAR writers not to use materials (the table, in this case) that are not part of the approved RSDP.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments:

   1. Because PRC-005, -008, -011, and -017 are related in the maintenance issues that they cover, there would be a benefit in consolidating these requirements of the standards into one standard.

   2. Specific concerns with this Standards at issue in this SAR:

a. PRC-006-0 would benefit from greater description as to the technical requirements. Specifically, R1.2.4 needs to be defined as to what particular generator protection schemes will be included in the requirement e.g. U/F trip settings.

b. R1.2.8 is too broad & encompassing in scope covering "any other schemes that are part of or impact the UFLS programs". The schemes that may be impacted by this requirement need to be defined in order to be measurable.

c. The levels of non-compliance should be augmented in PRC-006-0. For example, a level 2 non-compliance should be added for not meeting 2 or more elements of R1. A level 3 non-compliance should be added for not meeting R2. Level 4 non-compliance should be modified to target only those entities that do not complete a UFLS assessment within the last five years or those entities who do not provide this assessment to the regional entity.

d. As indicated by FERC, PRC-008 should be modified "to include a requirement that maintenance and testing of programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System."

3. The PRC Standards need to be reviewed to ensure applicable entities/functions are appropriately identified. For example, TOP's & LSEs' are missing from: (i) R1, R2 & M1 in PRC-007, and (ii) the Applicability, Requirements and Measures sections in PRC-008. In addition, in certain instances (PRC-007 & -008), because independent system operators and regional transmission organizations are TOPs, the PRC-007 and PRC-008 may not be appropriately applied to these entities, because such entities do not own/operate UFLS.

4. The SAR should consider deleting PRC-009, and add the requirements to PRC-006-0 as R1.4.3.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
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	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **Bonneville Power Transmission Services**

Lead Contact: **Lorissa Jones**

Contact Organization: **BPA Transmission Services - Reliability Program**

Contact Segment: **1**

Contact Telephone: **306-418-8978**

Contact E-mail: **ljjones@bpa.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Gary Keenan	BPA Transmission Services	**WECC**	1
Mike Viles	BPA Transmission Services	**WECC**	1

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments:

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments: BPA is in agreement with the scope of the proposed projects for PRC-006, PRC-007 and PRC-008, but not for PRC-009. The To Do List for PRC-009 notes a consideration from V0 Industry Comments of an exemption for those with shunt reactors who don't shed load. As these devices are more associated with UVLS than UFLS, BPA reccommends the removal of this item.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Mark Kuras	
Organization:	PJM	
Telephone:	610-666-8924	
E-mail:	kuras@pjm.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☒ **RFC** ☒ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: Suggest that the new UFLS shedding standard should be a continent-wide standard, or at the least, an Interconnection wide standard.

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: Suggest that the new UFLS shedding standard should be a continent-wide standard, or at the least, an Interconnection wide standard. If there is real concern about a decaying frequency, then all entities within the Interconnection should contribute to support the system frequency. Therefore a single set of UFLS criteria needs to be established and implemented. Any exceptions would clearly have to be identified and justified in using the NERC standards process.

   There should only be 7 requirements in this standard. These seven would be split between NERC and the entity that has installed UFLS devices.

   NERC establish what the UFLS criteria should be, which would include transmission and generation UFLS set-points, time-delays, etc.

   NERC should establish acceptable maintenance intervals

   NERC shall establish and maintain a database of all UFLS information

   NERC should conduct an assessment of its criteria every five years

   Each entity shall meet the established criteria

   Each entity shall update its information in the NERC database each year

   Each entity shall investigate and analyze all UFLS events

   The remaining requirements in the four standards should all go away. The entities would all be subject to compliance audits to verify their compliance

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: See above comments

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Michael Gammon	
Organization:	Kansas City Power & Light	
Telephone:	816-654-1242	
E-mail:	mike.gammon@kcpl.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: These standards are comprehensive, complete and clear in their requirements and expectations. Load shedding needs to be region specific to meet the emergency action and reaction needs of that region. For example, regions or areas that have limited import capability may have objectives to break into islands of generation and load to preserve as much of the area as possible, where a region rich in import capability may not have any objectives to break into islands, but rather shed load in a controlled manner to match the cabability of the generation in the region to keep up with the load change(s) resulting from the shedding of regional load.

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments:

   PRC-006

   "Lack of coordination" - It is probably a good idea to know and understand the UFLS program requirements of neighboring regions.

   "Develop Continent Standard" - The current standard is sufficient in scope and requirements to stand as a national standard. As stated above, the requirements are clear and complete to allow Regional Entities and their members to develop their unique UFLS programs, to implement them, to monitor the UFLS regional effectiveness and Regional member effectivness in maintaining their UFLS equipment. This standard serves a comprehensive national standard for developlement and implementation of UFLS in the regions.

   "Who submit compliance material to?" - I think it is understood by the industry all compliance programs are administered by Reliability Coordinators and does not need to be included in this standard.

   The remaining comments in this part of the SAR lack sufficient information to provide a specific response.

   PRC-007

   "Need language to implement" - I do not agree with the notion mentioned in the SAR document that it is necessary to add language requiring "implementation" of programs. The UFLS regional programs are required to specify in PRC-006 the frequency steps and load shed at a given step for TO's and Distribution Providers to adhere to. PRC-008 requires TO's and Distribution Providers to

maintain and test their UFLS equipment. It is not possible to comply with these standards without equipment installed in the field.

PRC-008
"Maintenance intervals not addressed" - I do agree that a minimum maintenance interval should be included in the standard for the industry to comment on. I imagine solid state relays and electromechanical relays probably have differing maintenance needs.

PRC-009
"No correseponding standard for under-voltage" - This comment is outside the scope of this standard. Any development of an under-voltage standard should be separate and distinct from the UFLS standard. Both UFLS and under-voltage involve shedding of load but to address different operating condition recovery.

General comments:
The remainder of the SAR items in the "To Do Lists" are basically editorial in nature and do not change the substance of the standard. I do not have any fundamental problems with making the suggested modifications to the standards, but I also do not see any great need either. It is unclear who the entity responsible for determining the interconnections setpoints should be.

3. Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.

☐ Yes

☐ No

Comments: To expand on the general comment above, the standards would be better organized by seperating the reliability requirements from the supporting text that explains the requirements. Measures should then be applied only to the requirements and not the text.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Mike Gentry	
Organization:	Salt River Project	
Telephone:	602-236-6408	
E-mail:	Mike.Gentry@srpnet.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs
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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments:

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☒ Yes

   ☐ No

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   Comments:

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments: None at this time.

Comment Form — 1st Draft of SAR for Underfrequency Load Shedding

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Verne Ingersoll	
Organization:	Progress Energy	
Telephone:	919-546-7534	
E-mail:	verne.ingersoll@pgnmail.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☒ **FRCC**	☐	2 — RTOs, ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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Lead Contact:

Contact Organization:

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Additional Member Name	Additional Member Organization	Region*	Segment*

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The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: Progress Energy supports the overall objective of developing standards at the NERC level whenever possible. Progress Energy believes that a revision to these set of standards provide this opportunity. In order to accomplish this objective, NERC should clearly identify the objectives to be accomplished by the standards (e.g. the "what"), but not be perscriptive on "how" these objectives should be accomplished. For example, these standards should clearly identify that the underfrequency load shedding should be accomplished in such a manner to prevent cascading outages. The owners, users and operators within a Region or sub-Region could establish additional coordination details that would be most applicable to the participants area on "how" this could most effectively be performed within their region/sub-region.

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: The SAR proposes to require each Regional Entity to write regional standards for UFLS. It is inappropriate for a NERC standard to apply to a Regional Entity or for a NERC standard to require an RE to write a standard. The reliability language states that standards will apply to owners, operators and users of the Bulk Power System. The REs are not owners, users or operators. The SAR should be revised to apply to appropriate owners, users and operators. In addition, the SAR should be revised to require that the owners, users and operators within a Region or sub-Region coodinate their UFLS programs. If the standards are correctly focused on the "what" needs to be accomplished via the standard, this will provide sufficient flexibility for the Regions or sub-Regions to develop coordinated approaches to "how" the standards should be implemented.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Perpetuo S. V. Tan	
Organization:	Los Angeles Department of Water & Power	
Telephone:	(818) 771-6776	
E-mail:	Perpetuo.Tan@ladwp.com	
NERC Region		**Registered Ballot Body Segment**
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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments:

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: Please see Attachment

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: Please see Attachment

ATTACHMENT TO

SAR Comment Form 2007-01 UFLS

Perpetuo S. V. Tan
Los Angeles Department of Water and Power
Energy Control Center
(818) 771-6776
Perpetuo.Tan@ladwp.com

Comments regarding the scope of the project (Question #2) and additional revisions that needs to be incorporated into the standards (Question #3).

The Reliability Functions checked off on page 3 of the SAR should include the Generator Owner and Generator Operator. This is because of the need to closely coordinate load tripping frequency settings to the generating unit off-nominal protection frequency and time delay settings. The objective is to provide enough separation between the load tripping and generating unit protection frequency and time delay settings. This will allow load tripping to be completed and thereby arrest system frequency decline without activating any generating unit off-nominal frequency protection.

The recommended generating unit off-nominal frequency protection settings vary depending on the unit manufacturer and type of unit. The number of generating units in an interconnection is numerous so will the variety of manufacturer's recommended off-nominal frequency and time delay settings. The worst case of these generating unit off-nominal protection settings have to be taken into account in determining the size of load tripped at each load-shedding step. If some units are not included in the consideration, it is possible for these units to have off-nominal settings that would trip the unit during load shedding, exacerbating the situation. A solution to this problem is requiring the owner of the generating unit to trip additional load to cover the additional loss of generation. But this solution is discriminatory if an extensive survey of generator off-nominal frequency protection was not conducted prior to the design of the load shedding steps. It would be similar to adding insult to injury to require generator owners to trip additional load when their generating units were excluded in the design of Regional Reliability Organization's (RRO) UFLS Program, in the first place. Besides these generator owners may not have load available for load shedding.

It is therefore important to add a requirement to "Standard PRC-006-0 – Development and Documentation of Regional UFLS programs that a thorough survey of all the off-nominal frequency protection settings of all interconnection generating units be conducted and the results used in the design of the RRO's Regional UFLS Program.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Richard Kafka	
Organization:	Pepco Holdings, Inc	
Telephone:	301-469-5274	
E-mail:	rjkafka@pepcoholdings.com	
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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments:

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.
   Comments:

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Lorne Midford	
Organization:	Manitoba Hydro	
Telephone:	204-487-5426	
E-mail:	lemidford@hydro.mb.ca; rgcoish@hydro.mb.ca	
NERC Region		**Registered Ballot Body Segment**
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   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: In any standard, there are certain conditions which ALL utilities should apply and/or follow, to maintain a consistent level of reliaibility. However, the standard should be written with enough flexibility to ensure that any uniquenesses in a given RRO are accounted for.

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments:

   General Comment:

   We support the requirement to upgrade standards, however, it is difficult to provide meaningful comments on the scope of work for this SAR. The SAR does not adequately communicate the proposed scope of work; it simply provides an encrypted list of requirements. NERC needs to rewrite the SAR to clearly communicate the scope of work to the stakeholders and the drafting team (beyond a summary table). A poorly written scope document will transfer into a poorly directed rewrite of a standard. Project Management 101.

   Detailed Comments:

   PRC – 007 – 0

   To Do List:

   - Need to include RA. [This should refer to the new functional model.]

   - Need to refine levels of compliance. [In what manner? Different percentages of insufficient UFLS at stated non-compliance levels? Perhaps 90%-80%-70% instead of the 95%-90%-85% presently stated?]

   PRC-008-0

   To Do List:

- Include a requirement that maintenance and testing of UFLS programs must be carried out with in a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System. [A maximum maintenance interval based on the relay type and system impact should not be defined by the standard. The required maintenance frequencies can not only be dependent upon relay type and system impact, but also many factors, including relay construction, age, maintenance practices, maintenance philosophies, environment, and operating context. The responsible entities are best situated to determine the maintenance requirements of their equipment. Revising PRC-008-0 requirements to be similar to the PRC-005-1 requirements provides more consistency across the standards and includes
R1.1. Maintenance and testing intervals and their basis.
R1.2. Summary of maintenance and testing intervals.
Both these requirements make available information which can be used for a review of an entity's maintenance frequencies and practices.]

PRC – 009 – 0

Requirements – Result or Outcome. [Do not agree the “results” are “missing”. The results are inherently implied by adhering to the conditions stated in the requirements. Same as for PRC-007.]

Measures - [M1 - Disagree.]

To Do List.

Change "program" to "standard" in R1. [Disagree. Using "standard" in this location of R1 could easily be confused with using the word "standard" in the rest of the document. There is nothing inappropriate with the word "program" in the context of R1. Same as for PRC-007.]

90 days vs 30 days. [Depending on complexity of UFLS involved disturbance, 90 days may be required to properly analyze event and document results.]

Exemptions for those with shunt reactor who don’t shed load. [Do not understand context of comment. Whether or not shunt reactors are tripped out by UF relays (possibly via UFLS relay facilities) is not relevant. Dumping reactors will increase voltages, but provide no significant (if any) improvements to sagging network frequency compared to load shedding.]

3. Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.

☒ Yes

☐ No

Comments:
PRC – 007 – 0

Purpose -

If each standard included a list of all other closely related standards, the individual non-repeated purposes of related standards could be more easily compared by readers when necessary.

Requirements – Shall Do What?

R2 – "As necessary" should be removed. Annual updates of UFLS data to the RRO are necessary, even if they just only confirm that the previous year's data is still valid. Please refer to R3 comment below.

R3 – Recommend further revision of R3. As well as RRO requested data within 30 days, there should be a mandatory requested annual update. This will coordinate with comment of R2.

Measures - 2M for 3R.

By making revisions to R2 and R3 as shown above, measure M2 will now appropriately cover both R2 and R3 for annual data updating and appropriate documentation transmission to RRO.

PRC-008-0

Measure M1 needs to be revised to clearly reflect the measures applied to Requirement R1.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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Organization:	Hydro-Québec TransÉnergie (HQTE)	
Telephone:	514 289-2211, ext. 2766	
E-mail:	champagne.roger.2@hydro.qc.ca	
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   ☐ No

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   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: HQTE agree with the scope which is essentially a broad review of these existing standards. It is our understanding that the information provided on the ``Standard Review Forms`` are just starting elements that will be considered by the SAR or Standards Drafting Team in their proposition for modifications to the existing standards.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments:

   To be a bit more specific, the scope could indicate, among other things, that violation risk factor and violation severity levels will be introduce.

   Since the scope is very broad, specific comments will be provided when actual revisions to the standards are proposed.

   Considering Québec Interconnection asynchronous ties, a particular concern for HQTE will be the technical requirements (frequency set points, size of loads, tripping times, etc…) that will be eventually proposed. These will probably be dealt with when regional standards will be specified.

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☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **Southern Company Transmission**

Lead Contact: **Roman Carter**

Contact Organization: **Southern Co. Transmission**

Contact Segment: **1**

Contact Telephone: **205.257.6027**

Contact E-mail: **jrcarter@southernco.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Marc Butts	Southern Co. Transmission	**SERC**	1
J.T. Wood	Southern Co. Transmisssion	**SERC**	1
Jim Busbin	Southern Co. Transmission	**SERC**	1
Jim Griffith	Southern Co. Transmission	**SERC**	1
Mike Oatts	Southern Co. Transmission	**SERC**	1
Rodney O'Bryant	Southern Co. Transmission	**SERC**	1
Barry Dyer	Alabama Power Co.	**SERC**	3
Jonathan Glidewell	Southern Co. Transmission	**SERC**	1
Roger Green	Southern Co. Generation	**SERC**	5
Bob Jones	Southern Co. Transmission	**SERC**	1

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following four standards:

PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-008 — Underfrequency Load Shedding Equipment Maintenance Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

The four standards associated with this project are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team will work with stakeholders to review PRC-006 and each of the current regional UFLS procedures to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: Southern feels that PRC-006 through PRC-009 are standards which need to address specific Regional development principles and therefore should be Regional Standards.

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments: While we agree with most of the Standard Review Forms, Southern does not agree that all recommendations contained in the To-Do-List from the Standard Review Forms are necessary. For example, while we agree the RC would utilize the UFLS as a means to relieve an emergency situation, we do not agree that the RC should be included in the Applicability section. There are no particular requirements that would address the RC and, therefore, it would be more appropriate for these standards to be applicable to the Load Serving Entity (LSE) or possibly the Transmission Owner (TO).

   Also, the term Evidence should be used in the Measurements in this standard as in other standards- it includes but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

Comments: Under PRC-006, Requirement 1.2, it is recommended the Regions have the responsibility for design details for determining Load Shedding Blocks (MWs), intentional and total tripping time delays, Generation protection, Islanding Schemes, Tie tripping schemes (within a Region), frequency set points (excludes BAL standard) and Load Restoration schemes. Also, the reporting of the time delay should only include the total time and not include the intentional time delay. The intentional time delay is included in the total time.

In PRC-006, Requirement 1.3, the Regional UFLS database is required to be updated at least every 5 years. However, under PRC-007, R2, the Transmission Owner is required to update its underfrequency data at least annually. These two timing update requirements should be consistent with one another.

In PRC-008 it is unclear how often the Transmission Owners are required to assess its maintenance and testing program. We recommend adding language to the SAR that says on a "as needed" basis.

Under PRC-008, Requirement 2, it states that Transmission Owner must implement its maintenance and testing program that is required in R1. It would seem more appropriate to include the implementation portion of R2 into R1 to say the Transmission Owner must have and implement a maintence and testing program.

The SAR drafting team should recognize that individual generator frequency trip set points are established by the manufacturer of the generator and not by the Generator Owner. Therefore, in the development of the underfrequency load shedding scheme, each Transmission Owner should recognize that these generator frequency trip settings cannot be adjusted and the load shedding schemes should take this into account. This standard should not require a Generator Owner to operate beyond the limits set by the manufacturer.

Comment Form — 1st Draft of SAR for Underfrequency Load Shedding

Please use this form to submit comments on the proposed SAR for Underfrequency Load Shedding (UFLS). Comments must be submitted by **January 12, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the abbreviation "UFLS" in the subject line. If you have questions please contact David Taylor at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs, ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 - Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **FRCC**

Lead Contact: **Eric Senkowicz**

Contact Organization: **FRCC**

Contact Segment: **2**

Contact Telephone: **813-289-5644**

Contact E-mail: **esenkowicz@frcc.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
John Odom	FRCC	**FRCC**	2
Alan Gale	City of Tallahassee	**FRCC**	5
Ted Hobson	JEA	**FRCC**	1
Garl Zimmerman	Seminole Electric Cooperative	**FRCC**	5
John Shaffer	Florida Power & Light	**FRCC**	1
Bob Schoneck	Florida Power & Light	**FRCC**	3

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following four standards:

PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-008 — Underfrequency Load Shedding Equipment Maintenance Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

The four standards associated with this project are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team will work with stakeholders to review PRC-006 and each of the current regional UFLS procedures to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 through PRC-009 have some "fill-in-the-blank" characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments:

   As stated in the SAR description, "PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard" and therefore some "fill-in-the-blank" characteristics cannot be eliminated and will need to be retained within the revised standard (requirements on regionally specific design criteria).

   We do agree that some requirements need clarification and upgrading in order to become mandatory and enforceable.

2. **Do you agree with the scope of the proposed project (the scope includes all the items noted on the "Standard Review Forms" attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?**

   ☒ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information.

   Comments:

   Aside from being broad and open-ended, the SAR Standard Review Form, To Do List, for PRC-006-0 includes two references not defined within the SAR, 1) (see recommendations for improvement), 2) (especially #21). We recommend relevant sections of the references be included in the final SAR and should be provided to the Standard Drafting Team.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☒ No

   Comments:

Consideration of Comments on 1st Draft of Underfrequency Load Shedding (UFLS) SAR

The Underfrequency Load Shedding (UFLS) SAR Drafting Team thanks all commenters who submitted comments on Draft 1 of the Underfrequency Load Shedding SAR. This SAR was posted for a 30-day public comment period from November 29, 2006 through January 12, 2007. The Underfrequency Load Shedding SAR Drafting Team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 26 sets of comments, including comments from 70 different people from more than 25 companies representing 6 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the SAR drafting team has revised the SAR for Project 2007-01. Changes made to Draft 1 of the SAR based on the comments received include:

1. PRC-008 was removed from the list of standards to be revised in association with Project 2007-01. The SAR drafting team agreed with a number of commenters that suggested grouping all the relay maintenance and testing standards into a single project. The SAR drafting team will request that NERC staff remove PRC-008 from Project 2007-01 and place it in a project with the following standards:
    - PRC-005 (currently in Project 2008-04)
    - PRC-008 (currently in Project 2007-01)
    - PRC-011 (currently in Project 2008-02)
    - PRC-017 (currently in Project 2008-04)
    - PRC-018 Requirement 6 (currently in Project 2007-011)
2. The SAR was revised to clarify the scope of work to be performed on each standard including the addition of Appendix A to the SAR. The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed, "Issues to Consider"), nor are the items identified in the "Issues to Consider" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be prohibited from addressing, at one time, all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. The SAR drafting team encourages all commenters to read Volume I of NERC's three-year reliability standards development plan, titled, *Reliability Standards Development Plan: 2007–2009* which identifies a set of specific issues each standard drafting team is to consider when revising a standard.
3. The Applicability section of the SAR was expanded to include Balancing Authority, Planning Authority/Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator. The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team will review the appropriate applicability of each of the standards.
4. The SAR drafting team noted a number of comments suggesting additional topics or issues to consider with the refinement of the standards. These comments have been noted and added to the SAR for resolution during standard drafting.
5. Other miscellaneous changes as noted in the report below.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the SAR can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Underfrequency_Load_Shedding.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Andrew Fusco	NCMPA				✓						
2.	Anthony Jablonski	ReliabilityFirst Corporation										✓
3.	Steve Myers	ERCOT		✓								
4.	Travis Sykes (TVA)	SERC EC Planning Standards Subc.	✓									
5.	Darrell Pace (Al. Elec. Coop.)	SERC EC Planning Standards Subc.	✓									
6.	Bob McGarrah (Ameren)	SERC EC Planning Standards Subc.	✓									
7.	Brian Moss (Duke, Carolinas)	SERC EC Planning Standards Subc.	✓									
8.	David Weekley (MEAG)	SERC EC Planning Standards Subc.	✓									
9.	Pat Huntley (SERC)	SERC EC Planning Standards Subc.										✓
10.	Phil Kleckley (SCE&G)	SERC EC Planning Standards Subc.			✓							
11.	Bob Jones (SOCO)	SERC EC Planning Standards Subc.	✓									
12.	Brian Thumm	ITC Transmission and MISO Stakeholders Standards Collaboration	✓									
13.	Charles Yeung (SPP)	IRC Standards Review Committee		✓								
14.	Alicia Daugherty (PJM)	IRC Standards Review Committee		✓								
15.	Mike Calimano (NYISO)	IRC Standards Review Committee		✓								
16.	Ron Falsetti (IESO)	IRC Standards Review Committee		✓								
17.	Matt Goldberg (ISO-NE)	IRC Standards Review Committee		✓								
18.	Brent Kingsford (CAISO)	IRC Standards Review Committee		✓								
19.	Anita Lee (AESO)	IRC Standards Review Committee		✓								
20.	Steve Myers (ERCOT)	IRC Standards Review Committee		✓								
21.	Bill Phillips (MISO)	IRC Standards Review Committee		✓								
22.	Ed Davis	Entergy Services, Inc.	✓									
23.	Eric Senkowicz	FRCC		✓								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
24.	John Odom	FRCC		✓								
25.	Alan Gale	City of Tallahassee					✓					
26.	Ted Hobson	Jacksonville Electric Authority	✓									
27.	Garl Zimmerman	Seminole Electric Cooperative					✓					
28.	John Shaffer	Florida Power & Light Company	✓									
29.	Bob Schoneck	Florida Power & Light Company			✓							
30.	Jason Marshall (MISO)	MISO Stakeholders Standards Collaboration		✓								
31.	Greg Berg	MISO Stakeholders Standards Collaboration	✓									
32.	Terry Bilke	MISO Stakeholders Standards Collaboration and MRO		✓								✓
33.	Jason Shaver	American Transmission Company	✓									
34.	James H. Sorrels, Jr.	American Electric Power	✓				✓	✓				
35.	John E. Sullivan	Ameren	✓									
36.	Dave Rudolph (BEPC)	MRO										✓
37.	Robert Coish (MHEB)	MRO										✓
38.	Carol Gerou (MP)	MRO										✓
39.	Ken Goldsmith (ALT)	MRO										✓
40.	Todd Gosnell (OPPD)	MRO										✓
41.	Jim Maenner (WPS)	MRO										✓
42.	Tom Mielnik (MEC)	MRO										✓
43.	Pam Oreschnick (XEL)	MRO										✓
44.	Dick Pursley (GRE)	MRO										✓
45.	Eric Ruskamp (LES)	MRO										✓
46.	Joe Knight (MRO)	MRO										✓
47.	Kathleen Goodman	ISO-NE		✓								
48.	Lorissa Jones	BPA Transmission Services	✓									
49.	Gary Keenan	BPA Transmission Services	✓									
50.	Mike Viles	BPA Transmission Services	✓									
51.	Mark Kuras	PJM		✓								
52.	Michael Gammon	KCP&L	✓									
53.	Mike Gentry	SRP	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
54.	Verne Ingersoll	Progress Energy	✓									
55.	Perpetuo S.V. Tan	LADWP	✓		✓		✓					
56.	Richard Kafka	Pepco Holdings, Inc.	✓									
57.	Lorne Midford	Manitoba Hydro	✓		✓		✓	✓				
58.	Roger Champagne	Hydro-Québec TransÉnergie (HQTE)	✓									
59.	Roman Carter	Southern Company Transmission	✓									
60.	Marc Butts	Southern Company Transmission	✓									
61.	J.T. Wood	Southern Company Transmission	✓									
62.	Jim Busbin	Southern Company Transmission	✓									
63.	Jim Griffith	Southern Company Transmission	✓									
64.	Mike Oatts	Southern Company Transmission	✓									
65.	Rodney O'Bryant	Southern Company Transmission	✓									
66.	Barry Dyer	Alabama Power Company			✓							
67.	Jonathan Glidewell	Southern Company Transmission	✓									
68.	Roger Green	Southern Company Generation					✓					
69.	Bob Jones	Southern Company Transmission	✓									
70.	Steve Myers	ERCOT		✓								

Index to Questions, Comments, and Responses:

1. **Do you believe that there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards?**

Summary Consideration: Most commenters did indicate they believe there is a reliability-related need to eliminate the "fill-in-the-blank" characteristics and upgrade the requirements in this set of standards. Several commenters questioned the reason for removing the "fill-in-the-blank" characteristics – FERC indicated that it does not believe these are enforceable. As envisioned, the drafting team, working with stakeholders, will identify requirements that can be applied on a continent-wide basis but may also identify requirements that need to be applied on an interconnection-wide or regional basis necessitated by physical differences in the bulk electric system. The revised SAR clarifies this intent.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Manitoba Hydro			In any standard, there are certain conditions which ALL utilities should apply and/or follow, to maintain a consistent level of reliability. However, the standard should be written with enough flexibility to ensure that any uniquenesses in a given RRO are accounted for.
Response: The SAR is written such that the standard drafting team is to determine if regional standards, interconnection-wide standards, or a continent-wide standard should be developed based upon technical reasons.			
SERC EC Planning Standards Subc.		☑	This seems to be a standard where fill-in-the-blank in the form of regional standards are needed.
Response: The SAR is written so that regional standards can be developed if there is technical reason for doing so.			
ITC Transmission		☑	While some improvement is probably necessary, it is not clear how removing "fill in the blank" characteristics will benefit reliability. Some Reliability Standards, such as the UFLS Standards, can benefit from a Regional coordination effort. Regional coordination in this case is preferred over an Interconnection-wide coordination effort.
Response: On May 11, 2006, FERC issued a report titled Federal Energy Regulatory Commission Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Mandatory Reliability Standards. In the report, FERC noted, among other things, that "[I] in the context of the mandatory Reliability Standards required by section 215 of the FPA, fill-in-the-blank standards raise two principal concerns: (i) they are not enforceable against users, owners and operators of the grid, but rather only provide broad direction to RROs; and (ii) the specific implementing standards adopted by the RROs have not undergone an approval process under section 215 and hence cannot themselves be enforced by the Commission or ERO." Under the current FERC rules the existing fill-in-the-blank aspects of standards are not enforceable under section 215 of the FPA. The drafting team believes that making these standards enforceable will improve compliance and therefore reliability. Further, the SAR is written so that regional standards can be developed if there is technical reason for doing so.			
Entergy Services, Inc.		☑	This seems to be a standard where fill-in-the-blank in the form of regional standards are needed.
Response: The SAR is written so that regional standards can be developed if there is technical reason for doing so.			
FRCC		☑	As stated in the SAR description, "PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements

Question #1			
Commenter	**Yes**	**No**	**Comment**
			that need to be defined by each regional entity in a regional standard" and therefore some "fill-in-the-blank" characteristics cannot be eliminated and will need to be retained within the revised standard (requirements on regionally specific design criteria). We do agree that some requirements need clarification and upgrading in order to become mandatory and enforceable.
Response: The SAR is written so that regional standards can be developed if there is technical reason for doing so.			
MISO Stakeholders Standards Collaboration		☑	While some improvement is probably necessary, it is not clear how removing "fill in the blank" characteristics will benefit reliability. While there is merit in having some interconnection view with regard to the standards, to ensure coordinated performance, the Regions currently play an important role. There are areas that have unique requirements that may not be adequately addressed by a continent-wide or interconnection-wide approach. This role should filled primarily as TOs, TOPs, DPs, and LSEs with the region coordinating the activities.
Response: On May 11, 2006, FERC issued a report titled Federal Energy Regulatory Commission Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Mandatory Reliability Standards. In the report, FERC noted, among other things, that "[I] in the context of the mandatory Reliability Standards required by section 215 of the FPA, fill-in-the-blank standards raise two principal concerns: (i) they are not enforceable against users, owners and operators of the grid, but rather only provide broad direction to RROs; and (ii) the specific implementing standards adopted by the RROs have not undergone an approval process under section 215 and hence cannot themselves be enforced by the Commission or ERO." Under the current FERC rules the existing fill-in-the-blank aspects of standards are not enforceable under section 215 of the FPA. The drafting team believes that making these standards enforceable will improve compliance and therefore reliability. Further, the SAR is written so that regional standards can be developed if there is technical reason for doing so.			
Ameren		☑	There is no reason to eliminate the fill-in-the-blank form of the standards. We believe that each region should continue to develop, coordinate, and maintain their own UFLS programs.
Response: On May 11, 2006, FERC issued a report titled Federal Energy Regulatory Commission Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Mandatory Reliability Standards. In the report, FERC noted, among other things, that "[I] in the context of the mandatory Reliability Standards required by section 215 of the FPA, fill-in-the-blank standards raise two principal concerns: (i) they are not enforceable against users, owners and operators of the grid, but rather only provide broad direction to RROs; and (ii) the specific implementing standards adopted by the RROs have not undergone an approval process under section 215 and hence cannot themselves be enforced by the Commission or ERO." Under the current FERC rules the existing fill-in-the-blank aspects of standards are not enforceable under section 215 of the FPA. The drafting team believes that making these standards enforceable will improve compliance and therefore reliability. Further, the SAR is written so that regional standards can be developed if there is technical reason for doing so.			
KCP&L		☑	These standards are comprehensive, complete and clear in their requirements and expectations. Load shedding needs to be region specific to meet the emergency action and reaction needs of that region. For example, regions or areas that have limited import

Question #1			
Commenter	**Yes**	**No**	**Comment**
			capability may have objectives to break into islands of generation and load to preserve as much of the area as possible, where a region rich in import capability may not have any objectives to break into islands, but rather shed load in a controlled manner to match the cabability of the generation in the region to keep up with the load change(s) resulting from the shedding of regional load.
Response: The SAR is written such that the standard drafting team is to determine if regional standards, interconnection-wide standards, or a continent-wide standard should be developed based upon technical reasons.			
So. Company Transmission, Generation, and Alabama Power		☑	Southern feels that PRC-006 through PRC-009 are standards which need to address specific Regional development principles and therefore should be Regional Standards.
Response: The SAR is written such that the standard drafting team is to determine if regional standards, interconnection-wide standards, or a continent-wide standard should be developed based upon technical reasons.			
PJM	☑		Suggest that the new UFLS shedding standard should be a continent-wide standard, or at the least, an Interconnection wide standard.
Response: On May 11, 2006, FERC issued a report titled Federal Energy Regulatory Commission Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Mandatory Reliability Standards. In the report, FERC noted, among other things, that "[I] in the context of the mandatory Reliability Standards required by section 215 of the FPA, fill-in-the-blank standards raise two principal concerns: (i) they are not enforceable against users, owners and operators of the grid, but rather only provide broad direction to RROs; and (ii) the specific implementing standards adopted by the RROs have not undergone an approval process under section 215 and hence cannot themselves be enforced by the Commission or ERO." Under the current FERC rules the existing fill-in-the-blank aspects of standards are not enforceable under section 215 of the FPA. The drafting team believes that making these standards enforceable will improve compliance and therefore reliability. Further, the SAR is written such that the standard drafting team is to determine if regional standards, interconnection-wide standards, or a continent-wide standard should be developed based upon technical reasons.			
ERCOT	☑		It is important for clear requirements to exist that meet the technical intent of the operations of UFLS as part of defense-in-depth to ensure the reliability of the BES. Because there are many different arrangements, organizational and contractual, among the various Regions, the standards must state the technical requirements that must be met ("what") and not prescribe "how".
Response: The SAR drafting team agrees and believes the standards must state the technical requirements that must be met ("what") and not prescribe "how" and that determination is in the scope of the review of these standards.			
American Transmission Company	☑		ATC agrees that there is a reliability related need to upgrade this set of standards.
Response: Thank you for your support.			
Progress Energy	☑		Progress Energy supports the overall objective of developing standards at the NERC level whenever possible. Progress Energy believes that a revision to these set of standards provide this opportunity. In order to accomplish this objective, NERC should clearly identify the

Question #1			
Commenter	**Yes**	**No**	**Comment**
			objectives to be accomplished by the standards (e.g. the "what"), but not be perscriptive on "how" these objectives should be accomplished. For example, these standards should clearly identify that the underfrequency load shedding should be accomplished in such a manner to prevent cascading outages. The owners, users and operators within a Region or sub-Region could establish additional coordination details that would be most applicable to the participants area on "how" this could most effectively be performed within their region/sub-region.
Response: The SAR drafting team agrees and believes the standards must state the technical requirements that must be met ("what") and not prescribe "how" and that determination is in the scope of the review of these standards.			
NCMPA	☑		
ReliabilityFirst Corporation	☑		
IRC Standards Review Committee	☑		
IESO	☑		
American Electric Power	☑		
MRO	☑		
ISO-NE	☑		
BPA Transmission Services	☑		
SRP	☑		
LADWP	☑		
Pepco Holdings, Inc.	☑		
Hydro-Québec TransÉnergie	☑		

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

Summary Consideration: Most commenters disagreed with the scope in the SAR and the drafting team modified the SAR as follows:

- Eliminated PRC-008 from the set of standards to be addressed in this project (PRC-008 should be reviewed and revised in conjunction with other standards that address maintenance and testing of protection and control devices)
- Added explanatory information to identify the source of the comments and issues identified in the attachments to the SAR and to clarify that these are issues to be addressed during standard drafting, not necessarily required changes to the standards
- Expanded the SAR to include a new attachment that lists suggested changes to the standards identified through this comment form and clarified that these are issues for the standard drafting team to address with stakeholders

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Commenter	**Yes**	**No**	**Comment**
NCMPA1		☑	NCMPA1 agrees with the need to develop measures to shed load during an underfrequency event that are consistent across the interconnected electric system. However, NCMPA1 disagrees with the approach that has been taken by the regions in responding to this requirement, and we are concerned that the same approach is suggested in this SAR. We are specifically concerned that it is simply not practical for smaller entities to comply with the requirements proposed by this SAR. As a result of the Energy Policy Act, many small utilities are required to register with their respective RROs, and these entities are now subject to mandatory compliance with the reliability standards. Some of these entities have peak annual loads that are smaller than 10 MW. Some are even smaller than 1 MW. Requirements within most, if not all, of the regions state that load must be shed in multiple steps (three steps in SERC, for example) at different underfrequency set points. While shedding load in multiple steps is perfectly rational for larger systems, most small loads are served by one distribution feeder bus. Furthermore, the entire peak demand on a small entity is a mere fraction of the amount of load that is shed by a larger entity in just one step. Furthermore, larger utilities have the advantage of aggregating load from multiple delivery points that can be shed in one step. Smaller entities do not have this advantage, and face the possibility of large expenditures in order to meet the multiple step shedding criteria. NCMPA1 questions the benefit to reliability by requiring all utilities, regardless of size, to

Question #2			
Commenter	**Yes**	**No**	**Comment**
			shed load in multiple steps as a result of an underfrequency event. We urge the SAR/standard drafting teams to address this issue and establish simplified requirements for small entities, whereby, • Compliance with the UFLS standards be non-compulsory for entities with annual peak demands less than 10 MW • Load shedding can be carried out in one step for entities with annual peak demands less than 100 MW.

Response: NCMPA1's comments are outside the scope of responsibility of the SAR drafting team to resolve. The comment has been noted and added to the SAR for resolution during standard drafting.

However, the purpose of the SAR identifies:

2. Ensure they are enforceable as mandatory reliability standards with financial penalties - the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.

In addition, Appendix A was added to the SAR for Project 2007-01 so that applicability and any limitations of the standards should be reviewed and revised as determined by the standard drafting team:

Applicability

Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Question #2			
Commenter	**Yes**	**No**	**Comment**
ReliabilityFirst Corporation		☑	Comment regarding acceptability of the scope of project: Inclusion of PRC-008, Maintenance and Testing, is not in the best interest of the development of the project or implementation of the project. Although PRC-008 does refer to the specific "relay system" known as UFLS, it more characteristic of the general subject area of "relay systems" which include: PRC-008-0 Underfrequency Load Shedding Equipment PRC-005-1 Transmission and Generator Protection System PRC-011-0 UVLS System PRC-017-0 Special Protection System Typically companies develop maintenance and testing programs that cover all types of "relay systems". Compliance to these four standards is usually checked from the same source reference. PRC-008 is independent of the analysis and implementation of an UFLS program. Project 2007-01 should only include PRC-006, 007 and 009.
Response: The SAR drafting team agrees with ReliabilityFirst Corporation's comment and recommends that the standards dealing with relay maintenance and testing be addressed in the same project (but not Project 2007-01): • PRC-005 (Project 2008-04) • PRC-008 (Project 2007-01) • PRC-011 (Project 2008-02) • PRC-017 (Project 2008-04) • PRC-018, Requirement 6 (Project 2007-011) The SAR drafting team will forward this recommendation to NERC staff for consideration.			
SERC EC Planning Standards Subc.		☑	The scope is not clearly defined. It is not clear how the items on pages 6 through 9 are to be incorporated. The items on these pages should be items for consideration by the SDT, but they are not necessarily required to be in the standard.
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard. Further, the scope of the SAR has been modified to delineate additional items the drafting team should consider but are not mandatory revisions.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
ITC Transmission		☑	SARs are supposed to clearly identify the scope of the proposed standard. SARS are intended to meet a specific industry need. This SAR appears to be a laundry-list garnered from various sources and ideas on what might be put in a standard. The scope of the proposed standard is not adequately addressed.
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard. In addition, the brief description of the SAR has been modified to add more clarity to the work. Please refer to the posted redlined version of the SAR (page 3 of 15) for the specific changes.			
IRC Standards Review Committee		☑	We agree with the general scope. However, the scope does not clearly state an important objective, for this and any standard revisions, that the end product should contain only the core reliability requirements without any guideline or procedure type of information. Further, we have concerns over the comments provided in the 4 tables. In fact, we question whether or not it is appropriate to include these tables in the SAR as they are not part of the appendices of the approved Reliability Standards Development Procedure (RSDP). It seems to us that this SAR has gone beyond the bound of established standard procedure. The comments in the Tables may not represent the majority view of the industry as we believe they have not been reviewed and commented by industry participants. Hence, these comments can at best be regarded as views of the person or group that prepared the table. But by being included in the SAR, these comments may mislead or restrict the thinking of the Standard Drafting Team in developing the revised standards. We ask the SAR Draft Team to please enlighten us on who provided these comments and how these comments got included in the SAR. We support moving forward with the standard development work according to the scope provided in the SAR, but urge the Standard Drafting Team to regard the comments in the Tables as personal views only that should be forwarded through the normal SAR commenting process. We also recommend that all future SAR writers not to use materials (the table, in this case) that are not part of the approved RSDP.
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List"			

Question #2			
Commenter	**Yes**	**No**	**Comment**
mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard. Further, the scope of the SAR has been modified to delineate additional items the drafting team should consider but are not mandatory revisions. The SAR drafting team encourages the commenter to read Volume I of NERC's three-year reliability standards development plan and the new Appendix A of the SAR to better understand the development of the "To Do List" identified for each standard in the plan.			
Entergy Services, Inc.		☑	The scope is not clearly defined. It is not clear how the items on pages 6 through 9 are to be incorporated. The items on these pages should be items for consideration by the SDT, but they are not necessarily required to be in the standard.
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard. Further, the scope of the SAR has been modified to delineate additional items the drafting team should consider but are not mandatory revisions.			
FRCC		☑	Aside from being broad and open-ended, the SAR Standard Review Form, To Do List, for PRC-006-0 includes two references not defined within the SAR, 1) (see recommendations for improvement), 2) (especially #21). We recommend relevant sections of the references be included in the final SAR and should be provided to the Standard Drafting Team.
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
Further, the scope of the SAR has been modified to delineate additional items the drafting team should consider but are not mandatory revisions.			
IESO	☑		We agree with the general scope; however, we have concerns over the comments provided in the 4 tables. In fact, we question whether or not it is appropriate to include these tables in the SAR as they are not part of the appendices of the approved Reliability Standards Development Procedure (RSDP). Page 14 (Version 6.0) of the RSDP clearly states that the objective as: A valid SAR that clearly justifies the purpose and describes the scope of the proposed standard action and conforms to the requirements of a SAR outlined in Appendix A. It seems to us that this SAR has gone beyond the bound of established standard procedure. These comments do not represent the majority view of the industry as we believe they have not been reviewed and commented by industry participants. Hence, these comments can at best be regarded as views of the person or group that prepared the table. But by being included in the SAR, these comments may mislead or restrict the thinking of the Standard Drafting Team in developing the revised standards. We support moving forward with the standard development work according to the scope provided in the SAR, but urge the Standard Drafting Team to regard these comments as personal views only that should be forwarded through the normal SAR commenting process. We also recommend that all future SAR writers not to use materials (the table, in this case) that are not part of the approved RSDP.
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard. Further, the scope of the SAR has been modified to delineate additional items the drafting team should consider but are not mandatory revisions. The SAR drafting team encourages the commenter to read Volume I of NERC's three-year reliability standards development plan and the new Appendix A of the SAR to better understand the development of the "To Do List" identified for each standard in the plan.			

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Commenter	**Yes**	**No**	**Comment**
MISO Stakeholders Standards Collaboration		☑	SARs are supposed to clearly identify the scope of the proposed standard. SARS are intended to meet a specific industry need. This SAR appears to be a laundry-list garnered from various sources and ideas on what might be put in a standard. It's unclear to us who is the agent or entity responsible for determining the interconnections' setpoints and overseeing the transition to any new requirements. It's also unclear who is accountable if the settings and process aren't correct. However, we do believe the TOs, TOPs, DPs and LSEs should have the responsibility to determine these settings with the Regions coordinating the activities.
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard. In addition, the brief description of the SAR has been modified to add more clarity to the work. Please refer to the posted redlined version of the SAR (page 3 of 15) for the specific changes.			
American Transmission Company		☑	The Applicability section in each of these standards is unclear and must be clarified in the new standards. PRC-006 We agree with the SAR Requestor that the Applicable section needs to be reassigned. With that being said the requestor did not provide the entity that should be responsible for these requirements. Failure to clearly identify, in the SAR, which entity is going to be assigned these requirements will make it difficult for the SDT to develop appropriate requirements. In assigning the appropriate entity the SAR drafting team needs to determine which entity has the authority or needs the authority to collect the data. ATC believes that there are only two options. The first is to assign the standard to the Regional Entities who has the authority to collect the data but is not subject to the FPA. The second option is to assign the standard to Planning Coordinators who are subject to the FPA but will need the authority to collect the data. Is this standard required to go through the formal standards development process if it is being assigned to Regional Entities? Once the SAR Drafting team determines the entity that will be assigned these

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Commenter	**Yes**	**No**	**Comment**
			requirements they must identify them in the "Reliability Function" section of the SAR. PRC-007, 008 and 009 The SAR drafting team must review of the Applicability section in each of these standards. The SAR currently states that the Applicability is "okay" but we believe that additional clarity and reassignment of requirements is needed. ATC recommends that Balancing Authorities and Generator Owners be added to the list of potential entities that may be assigned either new or existing requirements. ATC believes that any existing requirements assigned to the Transmission Operator should be reassigned to the appropriate entity. In addition, no new requirement should be assigned to the Transmission Operator. The Applicability section identifies entities in the following manner: 'Entity Name" required by its Regional Reliability Organization to own a UFLS program. The drafting teams should develop new language for identifying entities that are responsible for compliance with each standard.

Response: The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team is to review the appropriate applicability of the standard. The SAR drafting team added Balancing Authority and Generator Owner as the potential functional entities the revised standard might apply to.

The purpose of the SAR identifies:

2. Ensure they are enforceable as mandatory reliability standards with financial penalties - the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.

Appendix A was added to the SAR for Project 2007-01 so that applicability and any limitations of the standards should be reviewed and revised as determined by the standard drafting team:

Applicability

Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of

Question #2			
Commenter	**Yes**	**No**	**Comment**
			responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance? Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America. Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.
American Electric Power		☑	We support the proposed scope with the following exceptions: We do not support the development of Regional Standards for UFLS. Each interconnection should have an UFLS standard requirement(s), and those requirements should be applied consistently throughout the interconnection. Regional variations in UFLS requirements should be only considered in very special situations, such as for FRCC within the Eastern Interconnection. Thus, the SAR scope should include the objective to eliminate the existing Regional variations that exist today and develop interconnection wide UFLS standards. The scope should still include the ability for entities to submit technical justification for why an area within an interconnection should have a separate UFLS Standard requirement that is different the rest of the interconnection. But, the SAR scope should not include the present objective of maintaining the content of PRC-006 which requires each Region to define their UFLS requirements. Additionally, we would request that the drafting team consider geographic dispersion of the underfrequency response load. Lastly, we would request that this SAR apply to all entities that have an impact on the bulk energy system.
Response: The SAR is written such that the standard drafting team is to determine if regional standards, interconnection-wide standards, or a continent-wide standard should be developed based upon technical reasons. The last two comments from AEP are outside the scope of responsibility of the SAR drafting team to resolve. The comments have been noted and added to the SAR for resolution during standard drafting.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	The To Do Lists should be used as a guide to develop the scope of work for modifying these standards. However, these lists are not clear enough in themselves to constitute the scope of work for the Standard Drafting Team. These items should be considered by the Standard Drafting Team without necessarily requiring each item to become part of the reliability standards. The Standard need to include requirements for Generator Owners. (See comments under Item #3).
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard. Further, the scope of the SAR has been modified to delineate additional items the drafting team should consider but are not mandatory revisions. The SAR drafting team encourages the commenter to read Volume I of NERC's three-year reliability standards development plan and the new Appendix A of the SAR to better understand the development of the "To Do List" identified for each standard in the plan.			
MRO		☑	The MRO does NOT agree with the scope of the proposed project because the modification of these standards, PRC-006 through PRC-009, is a much more complex and detailed procedure than outlined in the scope. First, with FERC's recent announcement to remove the Regional Reliability Organizations (RRO's) from the Applicability section of ALL NERC standards, standard PRC-006 now needs to become a Regional Standard and be included in the Region's Delegation Agreement. Additionally, when a Regional Standard is developed for the UFLS program, the standard must enforce ALL member participation and that the UFLS study be customized and performed at a Regional level, not at a member level. The characteristics of each UFLS program may differ greatly between regions, thereby warranting a customized Regional Standard for each region. Finally, the MRO believes that the UFLS standards, PRC-007 through PRC-009 could be broadly applied to ALL entities that comply with a customized Regional UFLS standard. Therefore, for simplification purposes, the MRO would support combining standards PRC-007 through PRC-009 into one UFLS NERC standard.
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan			

Question #2			
Commenter	**Yes**	**No**	**Comment**
is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard. Further, the scope of the SAR has been modified to delineate additional items the drafting team should consider but are not mandatory revisions. The SAR is written such that the standard drafting team is to determine if regional standards, interconnection-wide standards, or a continent-wide standard should be developed based upon technical reasons. The last comment from the MRO is outside the scope of responsibility of the SAR drafting team to resolve. The comment has been noted and added to the SAR for resolution during standard drafting.			
ISO-NE		☑	We agree with the general scope. However, the scope does not clearly state an important objective, for this and any standard revisions, that the end product should contain only the core reliability requirements without any guideline or procedure type of information. Further, we have concerns over the comments provided in the 4 tables. In fact, we question whether or not it is appropriate to include these tables in the SAR as they are not part of the appendices of the approved Reliability Standards Development Procedure (RSDP). It seems to us that this SAR has gone beyond the bound of established standard procedure. These comments do not represent the majority view of the industry as we believe they have not been reviewed and commented by industry participants. Hence, these comments can at best be regarded as views of the person or group that prepared the table. But by being included in the SAR, these comments may mislead or restrict the thinking of the Standard Drafting Team in developing the revised standards. We support moving forward with the standard development work according to the scope provided in the SAR, but urge the Standard Drafting Team to regard these comments as personal views only that should be forwarded through the normal SAR commenting process. We also recommend that all future SAR writers not to use materials (the table, in this case) that are not part of the approved RSDP.
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is			

Question #2			
Commenter	**Yes**	**No**	**Comment**
to consider when revising a standard. Further, the scope of the SAR has been modified to delineate additional items the drafting team should consider but are not mandatory revisions. The SAR drafting team encourages the commenter to read Volume I of NERC's three-year reliability standards development plan and the new Appendix A of the SAR to better understand the development of the "To Do List" identified for each standard in the plan.			
BPA Transmission Services		☑	BPA is in agreement with the scope of the proposed projects for PRC-006, PRC-007 and PRC-008, but not for PRC-009. The To Do List for PRC-009 notes a consideration from V0 Industry Comments of an exemption for those with shunt reactors who don't shed load. As these devices are more associated with UVLS than UFLS, BPA reccommends the removal of this item.
Response: BPA's comment is outside the scope of responsibility of the SAR drafting team to resolve. The comment has been noted and added to the SAR for resolution during standard drafting.			
PJM		☑	Suggest that the new UFLS shedding standard should be a continent-wide standard, or at the least, an Interconnection wide standard. If there is real concern about a decaying frequency, then all entities within the Interconnection should contribute to support the system frequency. Therefore a single set of UFLS criteria needs to be established and implemented. Any exceptions would clearly have to be identified and justified in using the NERC standards process. There should only be 7 requirements in this standard. These seven would be split between NERC and the entity that has installed UFLS devices. • NERC establish what the UFLS criteria should be, which would include transmission and generation UFLS set-points, time-delays, etc. • NERC should establish acceptable maintenance intervals • NERC shall establish and maintain a database of all UFLS information • NERC should conduct an assessment of its criteria every five years • Each entity shall meet the established criteria • Each entity shall update its information in the NERC database each year • Each entity shall investigate and analyze all UFLS events The remaining requirements in the four standards should all go away. The entities would all be subject to compliance audits to verify their compliance
Response: The SAR is written such that the standard drafting team is to determine if regional standards, interconnection-wide standards, or a continent-wide standard should be developed based upon technical reasons. PJM's remaining comments are outside the scope of responsibility of the SAR drafting team to resolve. The comments have been noted and added to the SAR for resolution during standard drafting.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
KCP&L		☑	PRC-006 "Lack of coordination" - It is probably a good idea to know and understand the UFLS program requirements of neighboring regions. "Develop Continent Standard" - The current standard is sufficient in scope and requirements to stand as a national standard. As stated above, the requirements are clear and complete to allow Regional Entities and their members to develop their unique UFLS programs, to implement them, to monitor the UFLS regional effectiveness and Regional member effectivness in maintaining their UFLS equipment. This standard serves a comprehensive national standard for developlement and implementation of UFLS in the regions. "Who submit compliance material to?" - I think it is understood by the industry all compliance programs are administered by Reliability Coordinators and does not need to be included in this standard. The remaining comments in this part of the SAR lack sufficient information to provide a specific response. PRC-007 "Need language to implement" - I do not agree with the notion mentioned in the SAR document that it is necessary to add language requiring "implementation" of programs. The UFLS regional programs are required to specify in PRC-006 the frequency steps and load shed at a given step for TO's and Distribution Providers to adhere to. PRC-008 requires TO's and Distribution Providers to maintain and test their UFLS equipment. It is not possible to comply with these standards without equipment installed in the field. PRC-008 "Maintenance intervals not addressed" - I do agree that a minimum maintenance interval should be included in the standard for the industry to comment on. I imagine solid state relays and electromechanical relays probably have differing maintenance needs. PRC-009 "No correseponding standard for under-voltage" - This comment is outside the scope of this standard. Any development of an under-voltage standard should be separate and distinct from the UFLS standard. Both UFLS and under-voltage involve shedding of load but to address different operating condition recovery. General comments: The remainder of the SAR items in the "To Do Lists" are basically editorial in nature and do not change the substance of the standard. I do not have any fundamental problems

Question #2			
Commenter	**Yes**	**No**	**Comment**
			with making the suggested modifications to the standards, but I also do not see any great need either. It is unclear who the entity responsible for determining the interconnections setpoints should be.
Response: The majority of KCP&L's comments are outside the scope of the SAR drafting team to resolve. The comments have been noted and added to the SAR for resolution during standard drafting. With respect to KCP&L's final comment related to scope, the scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard.			
Progress Energy		☑	The SAR proposes to require each Regional Entity to write regional standards for UFLS. It is inappropriate for a NERC standard to apply to a Regional Entity or for a NERC standard to require an RE to write a standard. The reliability language states that standards will apply to owners, operators and users of the Bulk Power System. The REs are not owners, users or operators. The SAR should be revised to apply to appropriate owners, users and operators. In addition, the SAR should be revised to require that the owners, users and operators within a Region or sub-Region coordinate their UFLS programs. If the standards are correctly focused on the "what" needs to be accomplished via the standard, this will provide sufficient flexibility for the Regions or sub-Regions to develop coordinated approaches to "how" the standards should be implemented.
Response: The SAR is written such that the standard drafting team is to determine if regional standards, interconnection-wide standards, or a continent-wide standard should be developed based upon technical reasons. With respect to applicability, the purpose of the SAR identifies: 2. Ensure they are enforceable as mandatory reliability standards with financial penalties - the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear. In addition, Appendix A was added to the SAR for Project 2007-01 so that applicability and any limitations of the standards should be reviewed and revised as determined by the standard drafting team: **Applicability**			

Question #2			
Commenter	**Yes**	**No**	**Comment**
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance? Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America. Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.			
LADWP		☑	Comments regarding the scope of the project (Question #2) and additional revisions that needs to be incorporated into the standards (Question #3). The Reliability Functions checked off on page 3 of the SAR should include the Generator Owner and Generator Operator. This is because of the need to closely coordinate load tripping frequency settings to the generating unit off-nominal protection frequency and time delay settings. The objective is to provide enough separation between the load tripping and generating unit protection frequency and time delay settings. This will allow load tripping to be completed and thereby arrest system frequency decline without activating any generating unit off-nominal frequency protection. The recommended generating unit off-nominal frequency protection settings vary depending on the unit manufacturer and type of unit. The number of generating units in an interconnection is numerous so will the variety of manufacturer's recommended off-nominal frequency and time delay settings. The worst case of these generating unit off-nominal protection settings have to be taken into account in determining the size of load tripped at each load-shedding step. If some units are not included in the consideration, it is possible for these units to have off-nominal settings that would trip the unit during load shedding, exacerbating the situation. A solution to this problem is requiring the owner of the generating unit to trip additional load to cover the additional loss of generation. But this solution is discriminatory if an extensive survey of generator off-nominal frequency protection was not conducted prior to the design of the load shedding steps. It would be similar to adding insult to injury to require generator owners to trip

Question #2			
Commenter	**Yes**	**No**	**Comment**
			additional load when their generating units were excluded in the design of Regional Reliability Organization's (RRO) UFLS Program, in the first place. Besides these generator owners may not have load available for load shedding. It is therefore important to add a requirement to "Standard PRC-006-0 – Development and Documentation of Regional UFLS programs that a thorough survey of all the off-nominal frequency protection settings of all interconnection generating units be conducted and the results used in the design of the RRO's Regional UFLS Program.
Response: The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team is to review the appropriate applicability of the standard. The SAR drafting team added Generator Operator and Generator Owner as the potential functional entities the revised standard might apply to. The balance of LADWP's comments are outside the scope of responsibility of the SAR drafting team to resolve. The comments have been noted and added to the SAR for resolution during standard drafting.			
Manitoba Hydro		☑	General Comment: We support the requirement to upgrade standards, however, it is difficult to provide meaningful comments on the scope of work for this SAR. The SAR does not adequately communicate the proposed scope of work; it simply provides an encrypted list of requirements. NERC needs to rewrite the SAR to clearly communicate the scope of work to the stakeholders and the drafting team (beyond a summary table). A poorly written scope document will transfer into a poorly directed rewrite of a standard. Project Management 101. Detailed Comments: PRC – 007 – 0 To Do List: - Need to include RA. [This should refer to the new functional model.] - Need to refine levels of compliance. [In what manner? Different percentages of insufficient UFLS at stated non-compliance levels? Perhaps 90%-80%-70% instead of the 95%-90%-85% presently stated?] PRC-008-0 To Do List: - Include a requirement that maintenance and testing of UFLS programs must be carried out with in a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System. [A maximum maintenance interval based on the relay type and system impact should not be defined by the standard. The required

Question #2			
Commenter	**Yes**	**No**	**Comment**
			maintenance frequencies can not only be dependent upon relay type and system impact, but also many factors, including relay construction, age, maintenance practices, maintenance philosophies, environment, and operating context. The responsible entities are best situated to determine the maintenance requirements of their equipment. Revising PRC-008-0 requirements to be similar to the PRC-005-1 requirements provides more consistency across the standards and includes R1.1. Maintenance and testing intervals and their basis. R1.2. Summary of maintenance and testing intervals. Both these requirements make available information which can be used for a review of an entity's maintenance frequencies and practices.] PRC – 009 – 0 Requirements – Result or Outcome. [Do not agree the "results" are "missing". The results are inherently implied by adhering to the conditions stated in the requirements. Same as for PRC-007.] Measures - [M1 - Disagree.] To Do List. Change "program" to "standard" in R1. [Disagree. Using "standard" in this location of R1 could easily be confused with using the word "standard" in the rest of the document. There is nothing inappropriate with the word "program" in the context of R1. Same as for PRC-007.] 90 days vs. 30 days. [Depending on complexity of UFLS involved disturbance, 90 days may be required to properly analyze event and document results.] Exemptions for those with shunt reactor who don't shed load. [Do not understand context of comment. Whether or not shunt reactors are tripped out by UF relays (possibly via UFLS relay facilities) is not relevant. Dumping reactors will increase voltages, but provide no significant (if any) improvements to sagging network frequency compare
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
The SAR drafting team encourages the commenter to read Volume I of NERC's three-year reliability standards development plan and the new Appendix A of the SAR to better understand the development of the "To Do List" identified for each standard in the plan. Manitoba Hydro's comments have been added to the SAR for resolution during standard drafting.			
So. Company Transmission, Generation, and Alabama Power		☑	While we agree with most of the Standard Review Forms, Southern does not agree that all recommendations contained in the To-Do-List from the Standard Review Forms are necessary. For example, while we agree the RC would utilize the UFLS as a means to relieve an emergency situation, we do not agree that the RC should be included in the Applicability section. There are no particular requirements that would address the RC and, therefore, it would be more appropriate for these standards to be applicable to the Load Serving Entity (LSE) or possibly the Transmission Owner (TO). Also, the term Evidence should be used in the Measurements in this standard as in other standards- it includes but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence.
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard. The SAR drafting team encourages the commenter to read Volume I of NERC's three-year reliability standards development plan and the new Appendix A of the SAR to better understand the development of the "To Do List" identified for each standard in the plan. So. Company Transmission, Generation, and Alabama Power's last comment is outside the scope of responsibility of the SAR drafting team to resolve. The comment has been noted and added to the SAR for resolution during standard drafting.			
Hydro-Québec TransÉnergie	☑		HQTE agree with the scope which is essentially a broad review of these existing standards. It is our understanding that the information provided on the ``Standard Review Forms`` are just starting elements that will be considered by the SAR or Standards Drafting Team in their proposition for modifications to the existing standards.
Response: Hydro-Québec TransÉnergie is correct. The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as			

Question #2			
Commenter	**Yes**	**No**	**Comment**
supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard.			
SRP	☑		
ERCOT	☑		
Pepco Holdings, Inc.	☑		

3. Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.

Summary Consideration: Several stakeholders identified issues that should be resolved when the standards are refined. The drafting team expanded the SAR to include a new attachment that lists suggested changes to the standards identified through this comment form and clarified that these are issues for the standard drafting team to address with stakeholders

Question #3			
Commenter	**Yes**	**No**	**Comment**
NCMPA	☑		The top margin on pages SAR 5 through SAR 9 says "System Restoration and Blackstart". This appears to be some sort of editing mistake, and we recommend that it be changed to "Underfrequency Load Shedding".
Response: Thank you for the comment. The SAR has been revised.			
ERCOT		☑	In concert with the stated process, I do not believe it would be appropriate to go beyond what has been stated. Once these items have been "cleaned up", additional standards revisions may be proposed to address other concerns…using the standards revision process.
Response: The SAR has been revised to clarify the scope of the project.			
IRC Standards Review Committee	☑		Please take a closer look at the applicability of each of the standard requirements. We believe some of them may not cover all the responsible entities. For example: a. PRC-007-0 TOP's & LSE's are missing from R1, R2 & M1. b. PRC-008-0 TOP's & LSE's are missing from the Applicability, Requirements & Measures sections.
Response: The standard drafting team is to review the appropriate applicability of the standard's measures and requirements. The IRC Standards Review Committee's comments added to the SAR for resolution during standard drafting.			
MISO Stakeholders Standards Collaboration			This does not appear to be a yes-no question. One major change needed in all the standards is to separate the standard into two pieces. The first is the set of core reliability requirements. The second portion is the supporting text. More than half the text in the current standards is supporting text that explains the true requirements. Now NERC is in the process of developing measures for and assigning risk to sentences that were never intended to be measured.
Response: The MISO Stakeholders Standards Collaboration's comment has been added to the SAR for resolution during standard			

Question #3			
Commenter	**Yes**	**No**	**Comment**
drafting.			
American Transmission Company			The SAR fails to identity two existing standards that are related to this effort. 1) EOP-003-1 Load Shedding Plans. This standard will not be changed because of this work but the SDT should keep it in mind as they work on this set of standards. 2) PRC-005-1 Transmission and Generation Protection System Maintenance and Testing. This standard is identified in the review form for PRC-008-0 (page SAR-8). The SDT should consider if PRC-005 and PRC-008 could be combined into one single standard. At a minimum both of these standards should appear in the Related Standards section of the SAR. The SDT should also develop a new standard that addresses Generator Frequency Response. It's our opinion that Generator Frequency Response goes hand-in-hand with Under Frequency Load Shedding and therefore should be included in this set of standards.
Response: 1) EOP-003-1 was added to the Related Standards section of the SAR. 2) The SAR drafting team agrees with American Transmission Company's comment and recommends that the standards dealing with relay maintenance and testing be addressed in the same project (but not Project 2007-01): ▪ PRC-005 (Project 2008-04) ▪ PRC-008 (Project 2007-01) ▪ PRC-011 (Project 2008-02) ▪ PRC-017 (Project 2008-04) ▪ PRC-018, Requirement 6 (Project 2007-011) The SAR drafting team will forward this recommendation to NERC staff for consideration. ATC's last comment related to generator frequency response has been added to the SAR for resolution during standard drafting.			
American Electric Power			What is the technical basis of having varying Regional UFLS standards? Each Interconnection should have a consistent and coordinated UFLS standard requirement(s). Therefore, we support the development of Interconnection wide UFLS standards, not Regional standards within each interconnection, except for in situations that have technical justification to do otherwise. We would also request clarity regarding compliance measures. Some requirements will lend themselves to plus or minus tolerances for a prescribed value, while others may be best described in terms of greater than or less than the prescribed value. Additionally, Standard PRC-009 requires a simulation of the event (in addition to a

Question #3			
Commenter	**Yes**	**No**	**Comment**
			description, a review of the set points and tripping times, and a summary of the findings). The time frame associated with providing documentation of the analysis, following the underfrequency event, is 90 calendar days (Requirement R2). Based on our experiences, we would request that the drafting team consider a longer time frame, such as 120 days.
Response: The SAR is written such that the standard drafting team is to determine if regional standards, interconnection-wide standards, or a continent-wide standard should be developed based upon technical reasons. American Electric Power's last two comments are outside the scope of responsibility of the SAR drafting team to resolve. The comments have been noted and added to the SAR for resolution during standard drafting.			
Ameren			The standards need to be revised to include Generator Owners. In some cases generator owners want to set their underfrequency trip higher than regional requirements in order to conservatively protect their generating units. Presently the generator owners are not included in the Applicability section, therefore making enforcement of regional requirements difficult. The 'Apply to the Following Functions' section did not have Generator Owner as one of the entities selected, and the 'To Do List' also did not include this.
Response: The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team is to review the appropriate applicability of the standard. The SAR drafting team added Generator Owners as a potential functional entity the revised standard might apply to.			
ISO-NE			1. Because PRC-005, -008, -011, and -017 are related in the maintenance issues that they cover, there would be a benefit in consolidating these requirements of the standards into one standard. 2. Specific concerns with this Standards at issue in this SAR: a. PRC-006-0 would benefit from greater description as to the technical requirements. Specifically, R1.2.4 needs to be defined as to what particular generator protection schemes will be included in the requirement e.g. U/F trip settings. b. R1.2.8 is too broad & encompassing in scope covering "any other schemes that are part of or impact the UFLS programs". The schemes that may be impacted by this requirement need to be defined in order to be measurable. c. The levels of non-compliance should be augmented in PRC-006-0. For example, a level 2 non-compliance should be added for not meeting 2 or more elements of R1. A level 3 non-compliance should be added for not meeting R2. Level 4 non-compliance should be modified to target only those entities that do not complete a UFLS assessment within the last five years or those entities who do not provide this assessment to the regional entity. d. As indicated by FERC, PRC-008 should be modified "to include a requirement that

Question #3			
Commenter	**Yes**	**No**	**Comment**
			maintenance and testing of programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System." 3. The PRC Standards need to be reviewed to ensure applicable entities/functions are appropriately identified. For example, TOP's & LSEs' are missing from: (i) R1, R2 & M1 in PRC-007, and (ii) the Applicability, Requirements and Measures sections in PRC-008. In addition, in certain instances (PRC-007 & -008), because independent system operators and regional transmission organizations are TOPs, the PRC-007 and PRC-008 may not be appropriately applied to these entities, because such entities do not own/operate UFLS. 4. The SAR should consider deleting PRC-009, and add the requirements to PRC-006-0 as R1.4.3.
Response: The SAR drafting team agrees with ISO-NE's comment and recommends that the standards dealing with relay maintenance and testing be addressed in the same project (but not Project 2007-01): • PRC-005 (Project 2008-04) • PRC-008 (Project 2007-01) • PRC-011 (Project 2008-02) • PRC-017 (Project 2008-04) • PRC-018, Requirement 6 (Project 2007-011) The SAR drafting team will forward this recommendation to NERC staff for consideration. The balance of ISO-NE's comments are outside the scope of responsibility of the SAR drafting team to resolve. The comments have been noted and added to the SAR for resolution during standard drafting.			
PJM			See comments above.
Response: The SAR drafting team has responded to all comments above.			
KCP&L			To expand on the general comment above, the standards would be better organized by seperating the reliability requirements from the supporting text that explains the requirements. Measures should then be applied only to the requirements and not the text.
Response: KCP&L's comment has been added to the SAR for resolution during standard drafting.			
Manitoba Hydro			PRC – 007 – 0 Purpose - If each standard included a list of all other closely related standards, the individual non-repeated purposes of related standards could be more easily compared by readers when necessary.

Question #3			
Commenter	**Yes**	**No**	**Comment**
			Requirements – Shall Do What? R2 – "As necessary" should be removed. Annual updates of UFLS data to the RRO are necessary, even if they just only confirm that the previous year's data is still valid. Please refer to R3 comment below. R3 – Recommend further revision of R3. As well as RRO requested data within 30 days, there should be a mandatory requested annual update. This will coordinate with comment of R2. Measures - 2M for 3R. By making revisions to R2 and R3 as shown above, measure M2 will now appropriately cover both R2 and R3 for annual data updating and appropriate documentation transmission to RRO. PRC-008-0 Measure M1 needs to be revised to clearly reflect the measures applied to Requirement R1.
Response: Manitoba Hydro's comments are outside the scope of responsibility of the SAR drafting team to resolve. The comments have been noted and added to the SAR for resolution during standard drafting.			
Hydro-Québec TransÉnergie			To be a bit more specific, the scope could indicate, among other things, that violation risk factor and violation severity levels will be introduce. Since the scope is very broad, specific comments will be provided when actual revisions to the standards are proposed. Considering Québec Interconnection asynchronous ties, a particular concern for HQTE will be the technical requirements (frequency set points, size of loads, tripping times, etc…) that will be eventually proposed. These will probably be dealt with when regional standards will be specified.
Response: The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed to "Issues to Consider"), nor are the items identified in the "List" mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard.			
So. Company Transmission, Generation, and Alabama			Under PRC-006, Requirement 1.2, it is recommended the Regions have the responsibility for design details for determining Load Shedding Blocks (MWs), intentional and total

Question #3			
Commenter	**Yes**	**No**	**Comment**
Power			tripping time delays, Generation protection, Islanding Schemes, Tie tripping schemes (within a Region), frequency set points (excludes BAL standard) and Load Restoration schemes. Also, the reporting of the time delay should only include the total time and not include the intentional time delay. The intentional time delay is included in the total time. In PRC-006, Requirement 1.3, the Regional UFLS database is required to be updated at least every 5 years. However, under PRC-007, R2, the Transmission Owner is required to update its underfrequency data at least annually. These two timing update requirements should be consistent with one another. In PRC-008 it is unclear how often the Transmission Owners are required to assess its maintenance and testing program. We recommend adding language to the SAR that says on a "as needed" basis. Under PRC-008, Requirement 2, it states that Transmission Owner must implement its maintenance and testing program that is required in R1. It would seem more appropriate to include the implementation portion of R2 into R1 to say the Transmission Owner must have and implement a maintence and testing program. The SAR drafting team should recognize that individual generator frequency trip set points are established by the manufacturer of the generator and not by the Generator Owner. Therefore, in the development of the underfrequency load shedding scheme, each Transmission Owner should recognize that these generator frequency trip settings cannot be adjusted and the load shedding schemes should take this into account. This standard should not require a Generator Owner to operate beyond the limits set by the manufacturer.
Response: So. Company Transmission, Generation, and Alabama Power's comments are outside the scope of responsibility of the SAR drafting team to resolve. The comments have been noted and added to the SAR for resolution during standard drafting.			
SRP			None at this time.
MRO			The MRO does not have any additional comments at this time.
ReliabilityFirst Corporation		☑	
SERC EC Planning Standards Subc.		☑	

Standard Authorization Request Form
DRAFT 2 Dated 02/22/07 - REVISED

Title of Proposed Standard	Underfrequency Load Shedding (UFLS) Standards Project 2007-01
Request Date	November 14, 2006

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Regional Reliability Standards Working Group	☐	New Standard
Primary Contact	Robert W. Millard Director of Standards ReliabilityFirst Corporation	☒	Revision to existing Standards PRC-006, PRC-007, and PRC-009
Telephone Fax	(630) 261-2621 (630) 691-4222	☐	Withdrawal of existing Standard
E-mail	bob.millard@rfirst.org	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

PRC-006— Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

The purpose of revising the above standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems – ensure each of the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties - the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Incorporate other general improvements described in NERC's Reliability Standards Development Plan: 2007-2009 (summarized and outlined in the Reliability Standard Review Guidelines attached as Appendix A).
4. Consider the items mentioned in the Standard Review Forms (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) attached as Appendix B, prepared by the NERC staff, which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006) ,
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,
    - Version 0 standards development (see note 1), and
    - Regional Fill-in-the-Blank Team (RRSWG – a NERC working group involved with regional standards development).

    The standard drafting team should also consider any other issues that were not completely captured but were stated or referenced in the above materials.
5. Consider issues raised by the industry during the posting of the SAR for Project 2007-01 during the first comment period from November 29, 2006 through January 12, 2007, attached as Appendix C.
6. Satisfy the standards procedure requirement for five-year review of the standards.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

The standards in this set are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to stand up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team (SDT) will work with stakeholders to review PRC-006 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to and contained with the UFLS program documentation. The SDT shall determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 and PRC-009 have some 'fill-in-the-blank' characteristics as identified in the Regional Reliability Standards Working Group work plan which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest Reliability Authority.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Authority/ Planning Coordinator	Plans the Bulk Electric System.
☐	Resource Planner	Develops a long-term (>one year) plan for the resource adequacy of specific loads within a Planning Authority area.
☒	Transmission Planner	Develops a long-term (>one year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☒	Transmission Owner	Owns transmission facilities.
☒	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders.
☒	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer.
☒	Generator Owner	Owns and maintains generation unit(s).
☒	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity, and all necessary Interconnected Operations Services as required.
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.

☒	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
EOP-003-1	This standard may not be changed because of the work associated with Project 2007-01 but the standard drafting team should keep it in mind as they work on this set of standards.

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A: Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Mitigation Time Horizon
The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels
The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.

- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with 'Regional Entity'

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: PRC-006, PRC-007, and PRC-009 Standard Review Forms

Excerpted from NERC's Reliability Standards Development Plan: 2007 - 2009

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-006-0**	**Comments**
Title	Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs	Too long – slight difference with header.
Purpose		Implement vs. develop & document. Underfrequency spelled differently.
Applicability		RRO not in FM.
Requirements	*Conditions*	Okay
	Who?	R1.1 – includes sub-regions.
	Shall do what?	R1.3 – define sufficient; model at RRO or others or both? R1.4.2 – check grammar and capitalization; loosely worded. R2 & 3 – format of documentation.
	Result or Outcome	Missing
Measures		No real measures and definition of evidence required.
Issues to Consider	FERC NOPR o Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information. (see recommendations for improvement) FERC staff report o Concern with Blackout items (especially #21) o Fill in the blank o Definition of RRO as user of system o Lack of coordination Regional Fill-in-the-Blank Team Comments o Modify R1 to require each Region to develop a regional standard, and o Determine what elements (if any) of UFLS should be included in the North American standard and what elements should be included in the regional standards. o Development of regional standards needs to be coordinated with Regional entities. Regional entities should begin process for developing regional standards once the drafting team for the North American standard has determined what elements of UFLS should be included in the continent-wide standard and what elements should be included in the regional standards. o PRC-006 will be a continent-wide standard supported by Regional Reliability Standards. o Related PRC-007, PRC-008, and 009. V0 Industry Comments o Not a standalone standard o Who do you submit compliance material to? o Need to define evidence	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-007-0**	**Comments**
Title	Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organizations' Underfrequency Load Shedding Program Requirements	Too long and different than header.
Purpose		Same as 006 and doesn't address 007. No value proposition or benefit. Spelling of Underfrequency.
Applicability		Okay
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	R1 – what about coordination? R2 – provide format, etc. and define 'as necessary'.
	Result or Outcome	Missing
Measures		2 M for 3 R. M1 – define consistency M2 – define evidence
Issues to Consider	FERC NOPR o No changes identified. Regional Fill-in-the-Blank Team Comments o Change "program" to "standard" in R1. o Coordinated with PRC-006. o The regional procedures need to be converted to a standard to implement this. V0 Industry Comments o Need to include RA o Need to refine levels of non-compliance	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-009-0**	**Comments**
Title	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	Too long and different than header.
Purpose		Same as previous and it doesn't fit. No benefit or value proposition.
Applicability		Okay
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	Okay
	Result or Outcome	Missing
Measures		M1 not really a measure. M2 needs definition of evidence.
Issues to Consider	FERC NOPR o No changes identified. FERC staff report o No corresponding standard for under-voltage Regional Fill-in-the-Blank Team Comments o Change "program" to "standard'. o See notes for PRC-007. V0 Industry Comments o Define evidence o 90 days vs. 30 days o Exemptions for those with shunt reactors who don't shed load	

Appendix C: Issues Raised by Industry during 1st Posting of SAR for Project 2007-01

With respect to Question #2 of the comment form: *Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)*

NCMPA:

NCMPA1 agrees with the need to develop measures to shed load during an underfrequency event that are consistent across the interconnected electric system. However, NCMPA1 disagrees with the approach that has been taken by the regions in responding to this requirement, and we are concerned that the same approach is suggested in this SAR. We are specifically concerned that it is simply not practical for smaller entities to comply with the requirements proposed by this SAR.

As a result of the Energy Policy Act, many small utilities are required to register with their respective RROs, and these entities are now subject to mandatory compliance with the reliability standards. Some of these entities have peak annual loads that are smaller than 10 MW. Some are even smaller than 1 MW. Requirements within most, if not all, of the regions state that load must be shed in multiple steps (three steps in SERC, for example) at different underfrequency set points. While shedding load in multiple steps is perfectly rational for larger systems, most small loads are served by one distribution feeder bus. Furthermore, the entire peak demand on a small entity is a mere fraction of the amount of load that is shed by a larger entity in just one step. Furthermore, larger utilities have the advantage of aggregating load from multiple delivery points that can be shed in one step. Smaller entities do not have this advantage, and face the possibility of large expenditures in order to meet the multiple step shedding criteria.

NCMPA1 questions the benefit to reliability by requiring all utilities, regardless of size, to shed load in multiple steps as a result of an underfrequency event. We urge the SAR/standard drafting teams to address this issue and establish simplified requirements for small entities, whereby,

- Compliance with the UFLS standards be non-compulsory for entities with annual peak demands less than 10 MW
- Load shedding can be carried out in one step for entities with annual peak demands less than 100 MW.

American Electric Power

We would request that the drafting team consider geographic dispersion of the underfrequency response load.

We would request that this SAR apply to all entities that have an impact on the bulk energy system.

MRO

MRO believes that the UFLS standards, PRC-007 through PRC-009 could be broadly applied to ALL entities that comply with a customized Regional UFLS standard. Therefore, for simplification purposes, the MRO would support combining standards PRC-007 through PRC-009 into one UFLS NERC standard.

BPA Transmission Services

The To Do List for PRC-009 notes a consideration from V0 Industry Comments of an exemption for those with shunt reactors who don't shed load. As these devices are more associated with UVLS than UFLS, BPA reccommends the removal of this item.

PJM

There should only be 7 requirements in this standard. These seven would be split between NERC and the entity that has installed UFLS devices.

- NERC establish what the UFLS criteria should be, which would include transmission and generation UFLS set-points, time-delays, etc.
- NERC should establish acceptable maintenance intervals
- NERC shall establish and maintain a database of all UFLS information
- NERC should conduct an assessment of its criteria every five years
- Each entity shall meet the established criteria
- Each entity shall update its information in the NERC database each year
- Each entity shall investigate and analyze all UFLS events

The remaining requirements in the four standards should all go away. The entities would all be subject to compliance audits to verify their compliance

KCP&L

"Lack of coordination" - It is probably a good idea to know and understand the UFLS program requirements of neighboring regions.

"Develop Continent Standard" - The current standard is sufficient in scope and requirements to stand as a national standard. As stated above, the requirements are clear and complete to allow Regional Entities and their members to develop their unique UFLS programs, to implement them, to monitor the UFLS regional effectiveness and Regional member effectivness in maintaining their UFLS equipment. This standard serves a comprehensive national standard for developlement and implementation of UFLS in the regions.

"Who submit compliance material to?" - I think it is understood by the industry all compliance programs are administered by Reliability Coordinators and does not need to be included in this standard.

The remaining comments in this part of the SAR lack sufficient information to provide a specific response.

PRC-007

"Need language to implement" - I do not agree with the notion mentioned in the SAR document that it is necessary to add language requiring "implementation" of programs. The UFLS regional programs are required to specify in PRC-006 the frequency steps and load shed at a given step for TO's and Distribution Providers to adhere to. PRC-008 requires TO's and Distribution Providers to maintain and test their UFLS equipment. It is not possible to comply with these standards without equipment installed in the field.

PRC-008

"Maintenance intervals not addressed" - I do agree that a minimum maintenance interval should be included in the standard for the industry to comment on. I imagine solid state relays and electromechanical relays probably have differing maintenance needs.

PRC-009

"No correseponding standard for under-voltage" - This comment is outside the scope of this standard. Any development of an under-voltage standard should be separate and distinct from the UFLS standard. Both UFLS and under-voltage involve shedding of load but to address different operating condition recovery.

General comments:

The remainder of the SAR items in the "To Do Lists" are basically editorial in nature and do not change the substance of the standard. I do not have any fundamental problems with making the suggested modifications to the standards, but I also do not see any great need either. It is unclear who the entity responsible for determining the interconnections setpoints should be.

LADWP

Comments regarding the scope of the project (Question #2) and additional revisions that needs to be incorporated into the standards (Question #3).

The Reliability Functions checked off on page 3 of the SAR should include the Generator Owner and Generator Operator. This is because of the need to closely coordinate load tripping frequency settings to the generating unit off-nominal protection frequency and time delay settings. The objective is to provide enough separation between the load tripping and generating unit protection frequency and time delay settings. This will allow load tripping to be completed and thereby arrest system frequency decline without activating any generating unit off-nominal frequency protection.

The recommended generating unit off-nominal frequency protection settings vary depending on the unit manufacturer and type of unit. The number of generating units in an interconnection is numerous so will the variety of manufacturer's recommended off-nominal frequency and time delay settings. The worst case of these generating unit off-nominal protection settings have to be taken into account in determining the size of load tripped at each load-shedding step. If some units are not included in the consideration, it is possible for these units to have off-nominal settings that would trip the unit during load shedding, exacerbating the situation. A solution to this problem is requiring the owner of the generating unit to trip additional load to cover the additional loss of generation. But this solution is discriminatory if an extensive survey of generator off-nominal frequency protection was not conducted prior to the design of the load shedding steps. It would be similar to adding insult to injury to require generator owners to trip additional load when their generating units were excluded in the design of Regional Reliability Organization's (RRO) UFLS Program, in the first place. Besides these generator owners may not have load available for load shedding.

It is therefore important to add a requirement to "Standard PRC-006-0 – Development and Documentation of Regional UFLS programs that a thorough survey of all the off-nominal frequency protection settings of all interconnection generating units be conducted and the results used in the design of the RRO's Regional UFLS Program.

Manitoba Hydro

PRC-007 - To Do List:

- Need to include RA. [This should refer to the new functional model.]
- Need to refine levels of compliance. [In what manner? Different percentages of insufficient UFLS at stated non-compliance levels? Perhaps 90%-80%-70% instead of the 95%-90%-85% presently stated?]

PRC-008 - To Do List:

- Include a requirement that maintenance and testing of UFLS programs must be carried out with in a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System. [A maximum maintenance interval based on the relay type and system impact should not be defined by the standard. The required maintenance frequencies can not only be dependent upon relay type and system impact, but also many factors, including relay construction, age, maintenance practices, maintenance philosophies, environment, and operating context. The responsible entities are best situated to determine the maintenance requirements of their equipment. Revising PRC-008-0 requirements to be similar to the PRC-005-1 requirements provides more consistency across the standards and includes
  R1.1. Maintenance and testing intervals and their basis.
  R1.2. Summary of maintenance and testing intervals.

Both these requirements make available information which can be used for a review of an entity's maintenance frequencies and practices.]

PRC-009:

- Requirements – Result or Outcome. [Do not agree the “results” are “missing”. The results are inherently implied by adhering to the conditions stated in the requirements. Same as for PRC-007.]

Measures - [M1 - Disagree.]

To Do List:

- Change "program" to "standard" in R1. [Disagree. Using "standard" in this location of R1 could easily be confused with using the word "standard" in the rest of the document. There is nothing inappropriate with the word "program" in the context of R1. Same as for PRC-007.]
-90 days vs 30 days. [Depending on complexity of UFLS involved disturbance, 90 days may be required to properly analyze event and document results.]
-Exemptions for those with shunt reactor who don’t shed load. [Do not understand context of comment. Whether or not shunt reactors are tripped out by UF relays (possibly via UFLS relay facilities) is not relevant. Dumping reactors will increase voltages, but provide no significant (if any) improvements to sagging network frequency compare

So. Company Transmission, Generation, and Alabama Power

The term Evidence should be used in the Measurements in this standard as in other standards- it includes but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence.

With respect to Question #3 of the comment form: *Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.*

IRC Standards Review Committee

Please take a closer look at the applicability of each of the standard requirements. We believe some of them may not cover all the responsible entities. For example:

a. PRC-007-0

TOP's & LSE's are missing from R1, R2 & M1.

b. PRC-008-0

TOP's & LSE's are missing from the Applicability, Requirements & Measures sections.

MISO Stakeholders Committee

One major change needed in all the standards is to separate the standard into two pieces. The first is the set of core reliability requirements. The second portion is the supporting text. More than half the text in the current standards is supporting text that explains the true requirements. Now NERC is in the process of developing measures for and assigning risk to sentences that were never intended to be measured.

ATC

The SDT should also develop a new standard that addresses Generator Frequency Response. It’s our opinion that Generator Frequency Response goes hand-in-hand with Under Frequency Load Shedding and therefore should be included in this set of standards.

American Electric Power

We would request clarity regarding compliance measures. Some requirements will lend themselves to plus or minus tolerances for a prescribed value, while others may be best described in terms of greater than or less than the prescribed value.

Standard PRC-009 requires a simulation of the event (in addition to a description, a review of the set points and tripping times, and a summary of the findings). The time frame associated with providing documentation of the analysis, following the underfrequency event, is 90 calendar days (Requirement R2). Based on our experiences, we would request that the drafting team consider a longer time frame, such as 120 days.

ISO-NE

Because PRC-005, -008, -011, and -017 are related in the maintenance issues that they cover, there would be a benefit in consolidating these requirements of the standards into one standard.

PRC-006-0 would benefit from greater description as to the technical requirements. Specifically, R1.2.4 needs to be defined as to what particular generator protection schemes will be included in the requirement e.g. U/F trip settings.

R1.2.8 is too broad & encompassing in scope covering "any other schemes that are part of or impact the UFLS programs". The schemes that may be impacted by this requirement need to be defined in order to be measurable.

The levels of non-compliance should be augmented in PRC-006-0. For example, a level 2 non-compliance should be added for not meeting 2 or more elements of R1. A level 3 non-compliance should be added for not meeting R2. Level 4 non-compliance should be modified to target only those entities that do not complete a UFLS assessment within the last five years or those entities who do not provide this assessment to the regional entity.

As indicated by FERC, PRC-008 should be modified "to include a requirement that maintenance and testing of programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System."

The PRC Standards need to be reviewed to ensure applicable entities/functions are appropriately identified. TOP's & LSEs' are missing from: (i) R1, R2 & M1 in PRC-007, and (ii) the Applicability, Requirements and Measures sections in PRC-008. In addition, in certain instances (PRC-007 & -008), because independent system operators and regional transmission organizations are TOPs, the PRC-007 and PRC-008 may not be appropriately applied to these entities, because such entities do not own/operate UFLS.

The SAR should consider deleting PRC-009, and add the requirements to PRC-006-0 as R1.4.3.

KCP&L

The standards would be better organized by separating the reliability requirements from the supporting text that explains the requirements. Measures should then be applied only to the requirements and not the text.

Manitoba Hydro

PRC – 007:

- Purpose -If each standard included a list of all other closely related standards, the individual non-repeated purposes of related standards could be more easily compared by readers when necessary.
- Requirements – Shall Do What?
- R2 – "As necessary" should be removed. Annual updates of UFLS data to the RRO are necessary, even if they just only confirm that the previous year's data is still valid. Please refer to R3 comment below.
- R3 – Recommend further revision of R3. As well as RRO requested data within 30 days, there should be a mandatory requested annual update. This will coordinate with comment of R2.
- Measures - 2M for 3R.

- By making revisions to R2 and R3 as shown above, measure M2 will now appropriately cover both R2 and R3 for annual data updating and appropriate documentation transmission to RRO.

PRC-008-0:

Measure M1 needs to be revised to clearly reflect the measures applied to Requirement R1.

So. Company Transmission, Generation, and Alabama Power

Under PRC-006, Requirement 1.2, it is recommended the Regions have the responsibility for design details for determining Load Shedding Blocks (MWs), intentional and total tripping time delays, Generation protection, Islanding Schemes, Tie tripping schemes (within a Region), frequency set points (excludes BAL standard) and Load Restoration schemes. Also, the reporting of the time delay should only include the total time and not include the intentional time delay. The intentional time delay is included in the total time.

In PRC-006, Requirement 1.3, the Regional UFLS database is required to be updated at least every 5 years. However, under PRC-007, R2, the Transmission Owner is required to update its underfrequency data at least annually. These two timing update requirements should be consistent with one another.

In PRC-008 it is unclear how often the Transmission Owners are required to assess its maintenance and testing program. We recommend adding language to the SAR that says on a "as needed" basis.

Under PRC-008, Requirement 2, it states that Transmission Owner must implement its maintenance and testing program that is required in R1. It would seem more appropriate to include the implementation portion of R2 into R1 to say the Transmission Owner must have and implement a maintenance and testing program.

The SAR drafting team should recognize that individual generator frequency trip set points are established by the manufacturer of the generator and not by the Generator Owner. Therefore, in the development of the underfrequency load shedding scheme, each Transmission Owner should recognize that these generator frequency trip settings cannot be adjusted and the load shedding schemes should take this into account. This standard should not require a Generator Owner to operate beyond the limits set by the manufacturer.

Standard Authorization Request Form

DRAFT 2 Dated 02/22/07 - REVISED

Title of Proposed Standard	Underfrequency Load Shedding (UFLS) Standards Project 2007-01
Request Date	November 14, 2006

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Regional Reliability Standards Working Group	☐	New Standard
Primary Contact	Robert W. Millard Director of Standards ReliabilityFirst Corporation	☒	Revision to existing Standards PRC-006, PRC-007, ~~PRC-008,~~ and PRC-009
Telephone Fax	(630) 261-2621 (630) 691-4222	☐	Withdrawal of existing Standard
E-mail	bob.millard@rfirst.org	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

PRC-006— Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
~~PRC-008 — Underfrequency Load Shedding Equipment Maintenance Programs~~
PRC-009 — UFLS Performance Following an Underfrequency Event

The purpose of revising the above ~~four~~ standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems ~~.~~ — ensure each of the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties - the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.

~~3.~~Incorporate other general improvements described in ~~the standards development work plan.~~

3. ~~Consider comments received during the initial development of the standards~~NERC's Reliability Standards Development Plan: 2007-2009 (summarized and ~~other comments received from ERO regulatory authorities and stakeholders, as noted~~outlined in the Reliability Standard Review Guidelines attached ~~review sheets~~as Appendix A).
4. Consider the items mentioned in the Standard Review Forms (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) attached as Appendix B, prepared by the NERC staff, which attempt to capture comments from the:
   - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006) ,
   - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,
   - Version 0 standards development (see note 1), and
   - Regional Fill-in-the-Blank Team (RRSWG – a NERC working group involved with regional standards development).

   The standard drafting team should also consider any other issues that were not completely captured but were stated or referenced in the above materials.
5. Consider issues raised by the industry during the posting of the SAR for Project 2007-01 during the first comment period from November 29, 2006 through January 12, 2007, attached as Appendix C.
6. Satisfy the standards procedure requirement for five-year review of the standards.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

The ~~four~~ standards in this set are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to stand up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team (SDT) will work with stakeholders to review PRC-006 and each of the current regional ~~UFLS procedures~~programs developed in accordance with that standard, including any other associated programs and/or requirements related to and contained with the UFLS program documentation. The SDT shall determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 ~~through~~and PRC-009 have some 'fill-in-the-blank' characteristics as identified in the Regional Reliability Standards Working Group work plan which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest Reliability Authority.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Authority/ Planning Coordinator	Plans the Bulk Electric System.
☐	Resource Planner	Develops a long-term (>one year) plan for the resource adequacy of specific loads within a Planning Authority area.
☒	Transmission Planner	Develops a long-term (>one year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☒	Transmission Owner	Owns transmission facilities.
☒	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders.
☒	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer.
☒	Generator Owner	Owns and maintains generation unit(s).
☒	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity, and all necessary Interconnected Operations Services as required.
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.

☒	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
EOP-003-1	This standard may not be changed because of the work associated with Project 2007-01 but the standard drafting team should keep it in mind as they work on this set of standards.

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A: Reliability Standard Review Guidelines

Applicability

Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose

Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements

Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability

Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations

Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness

Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Mitigation Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.

- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with 'Regional Entity'

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: PRC-006, PRC-007, and PRC-009 Standard Review Forms

Excerpted from NERC's Reliability Standards Development Plan: 2007 - 2009

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-006-0**	**Comments**
Title	Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs	Too long – slight difference with header.
Purpose		Implement vs. develop & document. Underfrequency spelled differently.
Applicability		RRO not in FM.
Requirements	*Conditions*	Okay
	Who?	R1.1 – includes sub-regions.
	Shall do what?	R1.3 – define sufficient; model at RRO or others or both? R1.4.2 – check grammar and capitalization; loosely worded. R2 & 3 – format of documentation.
	Result or Outcome	Missing
Measures		No real measures and definition of evidence required.
~~**To Do List**~~**Issues to Consider**	FERC NOPR o Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information. (see recommendations for improvement) FERC staff report o Concern with Blackout items (especially #21) o Fill in the blank o Definition of RRO as user of system o Lack of coordination Regional Fill-in-the-Blank Team Comments o Modify R1 to require each Region to develop a regional standard, and o Determine what elements (if any) of UFLS should be included in the North American standard and what elements should be included in the regional standards. o Development of regional standards needs to be coordinated with Regional entities. Regional entities should begin process for developing regional standards once the drafting team for the North American standard has determined what elements of UFLS should be included in the continent-wide standard and what elements should be included in the regional standards. o PRC-006 will be a continent-wide standard supported by Regional Reliability Standards. o Related PRC-007, PRC-008, and 009. V0 Industry Comments o Not a standalone standard o Who do you submit compliance material to? o Need to define evidence	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-007-0**	**Comments**
Title	Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organizations' Underfrequency Load Shedding Program Requirements	Too long and different than header.
Purpose		Same as 006 and doesn't address 007. No value proposition or benefit. Spelling of Underfrequency.
Applicability		Okay
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	R1 – what about coordination? R2 – provide format, etc. and define 'as necessary'.
	Result or Outcome	Missing
Measures		2 M for 3 R. M1 – define consistency M2 – define evidence
~~**To Do List**~~**Issues to Consider**	FERC NOPR o No changes identified. Regional Fill-in-the-Blank Team Comments o Change "program" to "standard" in R1. o Coordinated with PRC-006. o The regional procedures need to be converted to a standard to implement this. V0 Industry Comments o Need to include RA o Need to refine levels of non-compliance	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-008-0**	**Comments**
Title	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	Too long and different than header. Doesn't cover testing element.
Purpose		Same statement that has been carried forward and doesn't fit here. No benefit or value proposition.
Applicability		Okay
Requirements	*Conditions*	Not clear how this differs from 005.
	Who?	Okay
	Shall do what?	R2 – format, etc. missing.
	Result or Outcome	Missing
Measures		M2 needs to define evidence.
To Do List	FERC NOPR oInclude a requirement that maintenance and testing of UFLS programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk Power System. FERC staff report oMaintenance intervals not addressed Regional Fill-in-the-Blank Team Comments oOkay if PRC-006 is fixed V0 Industry Comments oConsistent wording from standard to standard required oDefinition of evidence required	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-009-0**	**Comments**
Title	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	Too long and different than header.
Purpose		Same as previous and it doesn't fit. No benefit or value proposition.
Applicability		Okay
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	Okay
	Result or Outcome	Missing
Measures		M1 not really a measure. M2 needs definition of evidence.
~~To Do List~~Issues to Consider	FERC NOPR o No changes identified. FERC staff report o No corresponding standard for under-voltage Regional Fill-in-the-Blank Team Comments o Change "program" to "standard'. o See notes for PRC-007. V0 Industry Comments o Define evidence o 90 days vs. 30 days o Exemptions for those with shunt reactors who don't shed load	

Appendix C: Issues Raised by Industry during 1st Posting of SAR for Project 2007-01

With respect to Question #2 of the comment form: *Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)*

NCMPA:

NCMPA1 agrees with the need to develop measures to shed load during an underfrequency event that are consistent across the interconnected electric system. However, NCMPA1 disagrees with the approach that has been taken by the regions in responding to this requirement, and we are concerned that the same approach is suggested in this SAR. We are specifically concerned that it is simply not practical for smaller entities to comply with the requirements proposed by this SAR.

As a result of the Energy Policy Act, many small utilities are required to register with their respective RROs, and these entities are now subject to mandatory compliance with the reliability standards. Some of these entities have peak annual loads that are smaller than 10 MW. Some are even smaller than 1 MW. Requirements within most, if not all, of the regions state that load must be shed in multiple steps (three steps in SERC, for example) at different underfrequency set points. While shedding load in multiple steps is perfectly rational for larger systems, most small loads are served by one distribution feeder bus. Furthermore, the entire peak demand on a small entity is a mere fraction of the amount of load that is shed by a larger entity in just one step. Furthermore, larger utilities have the advantage of aggregating load from multiple delivery points that can be shed in one step. Smaller entities do not have this advantage, and face the possibility of large expenditures in order to meet the multiple step shedding criteria.

NCMPA1 questions the benefit to reliability by requiring all utilities, regardless of size, to shed load in multiple steps as a result of an underfrequency event. We urge the SAR/standard drafting teams to address this issue and establish simplified requirements for small entities, whereby,

- Compliance with the UFLS standards be non-compulsory for entities with annual peak demands less than 10 MW
- Load shedding can be carried out in one step for entities with annual peak demands less than 100 MW.

American Electric Power

We would request that the drafting team consider geographic dispersion of the underfrequency response load.

We would request that this SAR apply to all entities that have an impact on the bulk energy system.

MRO

MRO believes that the UFLS standards, PRC-007 through PRC-009 could be broadly applied to ALL entities that comply with a customized Regional UFLS standard. Therefore, for simplification purposes, the MRO would support combining standards PRC-007 through PRC-009 into one UFLS NERC standard.

BPA Transmission Services

The To Do List for PRC-009 notes a consideration from V0 Industry Comments of an exemption for those with shunt reactors who don't shed load. As these devices are more associated with UVLS than UFLS, BPA reccommends the removal of this item.

PJM

There should only be 7 requirements in this standard. These seven would be split between NERC and the entity that has installed UFLS devices.

- NERC establish what the UFLS criteria should be, which would include transmission and generation UFLS set-points, time-delays, etc.
- NERC should establish acceptable maintenance intervals
- NERC shall establish and maintain a database of all UFLS information
- NERC should conduct an assessment of its criteria every five years
- Each entity shall meet the established criteria
- Each entity shall update its information in the NERC database each year
- Each entity shall investigate and analyze all UFLS events

The remaining requirements in the four standards should all go away. The entities would all be subject to compliance audits to verify their compliance

KCP&L

"Lack of coordination" - It is probably a good idea to know and understand the UFLS program requirements of neighboring regions.

"Develop Continent Standard" - The current standard is sufficient in scope and requirements to stand as a national standard. As stated above, the requirements are clear and complete to allow Regional Entities and their members to develop their unique UFLS programs, to implement them, to monitor the UFLS regional effectiveness and Regional member effectivness in maintaining their UFLS equipment. This standard serves a comprehensive national standard for developlement and implementation of UFLS in the regions.

"Who submit compliance material to?" - I think it is understood by the industry all compliance programs are administered by Reliability Coordinators and does not need to be included in this standard.

The remaining comments in this part of the SAR lack sufficient information to provide a specific response.

PRC-007

"Need language to implement" - I do not agree with the notion mentioned in the SAR document that it is necessary to add language requiring "implementation" of programs. The UFLS regional programs are required to specify in PRC-006 the frequency steps and load shed at a given step for TO's and Distribution Providers to adhere to. PRC-008 requires TO's and Distribution Providers to maintain and test their UFLS equipment. It is not possible to comply with these standards without equipment installed in the field.

PRC-008

"Maintenance intervals not addressed" - I do agree that a minimum maintenance interval should be included in the standard for the industry to comment on. I imagine solid state relays and electromechanical relays probably have differing maintenance needs.

PRC-009

"No corresponding standard for under-voltage" - This comment is outside the scope of this standard. Any development of an under-voltage standard should be separate and distinct from the UFLS standard. Both UFLS and under-voltage involve shedding of load but to address different operating condition recovery.

General comments:

The remainder of the SAR items in the "To Do Lists" are basically editorial in nature and do not change the substance of the standard. I do not have any fundamental problems with making the suggested modifications to the standards, but I also do not see any great need either. It is unclear who the entity responsible for determining the interconnections setpoints should be.

LADWP

Comments regarding the scope of the project (Question #2) and additional revisions that needs to be incorporated into the standards (Question #3).

The Reliability Functions checked off on page 3 of the SAR should include the Generator Owner and Generator Operator. This is because of the need to closely coordinate load tripping frequency settings to the generating unit off-nominal protection frequency and time delay settings. The objective is to provide enough separation between the load tripping and generating unit protection frequency and time delay settings. This will allow load tripping to be completed and thereby arrest system frequency decline without activating any generating unit off-nominal frequency protection.

The recommended generating unit off-nominal frequency protection settings vary depending on the unit manufacturer and type of unit. The number of generating units in an interconnection is numerous so will the variety of manufacturer's recommended off-nominal frequency and time delay settings. The worst case of these generating unit off-nominal protection settings have to be taken into account in determining the size of load tripped at each load-shedding step. If some units are not included in the consideration, it is possible for these units to have off-nominal settings that would trip the unit during load shedding, exacerbating the situation. A solution to this problem is requiring the owner of the generating unit to trip additional load to cover the additional loss of generation. But this solution is discriminatory if an extensive survey of generator off-nominal frequency protection was not conducted prior to the design of the load shedding steps. It would be similar to adding insult to injury to require generator owners to trip additional load when their generating units were excluded in the design of Regional Reliability Organization's (RRO) UFLS Program, in the first place. Besides these generator owners may not have load available for load shedding.

It is therefore important to add a requirement to "Standard PRC-006-0 – Development and Documentation of Regional UFLS programs that a thorough survey of all the off-nominal frequency protection settings of all interconnection generating units be conducted and the results used in the design of the RRO's Regional UFLS Program.

Manitoba Hydro

PRC-007 - To Do List:

- Need to include RA. [This should refer to the new functional model.]
- Need to refine levels of compliance. [In what manner? Different percentages of insufficient UFLS at stated non-compliance levels? Perhaps 90%-80%-70% instead of the 95%-90%-85% presently stated?]

PRC-008 - To Do List:

- Include a requirement that maintenance and testing of UFLS programs must be carried out with in a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System. [A maximum maintenance interval based on the relay type and system impact should not be defined by the standard. The required maintenance frequencies can not only be dependent upon relay type and system impact, but also many factors, including relay construction, age, maintenance practices, maintenance philosophies, environment, and operating context. The responsible entities are best situated to determine the maintenance requirements of their equipment. Revising PRC-008-0 requirements to be similar to the PRC-005-1 requirements provides more consistency across the standards and includes
  R1.1. Maintenance and testing intervals and their basis.
  R1.2. Summary of maintenance and testing intervals.

Both these requirements make available information which can be used for a review of an entity's maintenance frequencies and practices.]

PRC-009:

- Requirements – Result or Outcome. [Do not agree the "results" are "missing". The results are inherently implied by adhering to the conditions stated in the requirements. Same as for PRC-007.]

Measures - [M1 - Disagree.]

To Do List:

- Change "program" to "standard" in R1. [Disagree. Using "standard" in this location of R1 could easily be confused with using the word "standard" in the rest of the document. There is nothing inappropriate with the word "program" in the context of R1. Same as for PRC-007.]
-90 days vs 30 days. [Depending on complexity of UFLS involved disturbance, 90 days may be required to properly analyze event and document results.]
-Exemptions for those with shunt reactor who don't shed load. [Do not understand context of comment. Whether or not shunt reactors are tripped out by UF relays (possibly via UFLS relay facilities) is not relevant. Dumping reactors will increase voltages, but provide no significant (if any) improvements to sagging network frequency compare

So. Company Transmission, Generation, and Alabama Power

The term Evidence should be used in the Measurements in this standard as in other standards- it includes but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence.

With respect to Question #3 of the comment form: *Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.*

IRC Standards Review Committee

Please take a closer look at the applicability of each of the standard requirements. We believe some of them may not cover all the responsible entities. For example:

a. PRC-007-0

TOP's & LSE's are missing from R1, R2 & M1.

b. PRC-008-0

TOP's & LSE's are missing from the Applicability, Requirements & Measures sections.

MISO Stakeholders Committee

One major change needed in all the standards is to separate the standard into two pieces. The first is the set of core reliability requirements. The second portion is the supporting text. More than half the text in the current standards is supporting text that explains the true requirements. Now NERC is in the process of developing measures for and assigning risk to sentences that were never intended to be measured.

ATC

The SDT should also develop a new standard that addresses Generator Frequency Response. It's our opinion that Generator Frequency Response goes hand-in-hand with Under Frequency Load Shedding and therefore should be included in this set of standards.

American Electric Power

We would request clarity regarding compliance measures. Some requirements will lend themselves to plus or minus tolerances for a prescribed value, while others may be best described in terms of greater than or less than the prescribed value.

Standard PRC-009 requires a simulation of the event (in addition to a description, a review of the set points and tripping times, and a summary of the findings). The time frame associated with providing documentation of the analysis, following the underfrequency event, is 90 calendar days (Requirement R2). Based on our experiences, we would request that the drafting team consider a longer time frame, such as 120 days.

ISO-NE

Because PRC-005, -008, -011, and -017 are related in the maintenance issues that they cover, there would be a benefit in consolidating these requirements of the standards into one standard.

PRC-006-0 would benefit from greater description as to the technical requirements. Specifically, R1.2.4 needs to be defined as to what particular generator protection schemes will be included in the requirement e.g. U/F trip settings.

R1.2.8 is too broad & encompassing in scope covering "any other schemes that are part of or impact the UFLS programs". The schemes that may be impacted by this requirement need to be defined in order to be measurable.

The levels of non-compliance should be augmented in PRC-006-0. For example, a level 2 non-compliance should be added for not meeting 2 or more elements of R1. A level 3 non-compliance should be added for not meeting R2. Level 4 non-compliance should be modified to target only those entities that do not complete a UFLS assessment within the last five years or those entities who do not provide this assessment to the regional entity.

As indicated by FERC, PRC-008 should be modified "to include a requirement that maintenance and testing of programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System."

The PRC Standards need to be reviewed to ensure applicable entities/functions are appropriately identified. TOP's & LSEs' are missing from: (i) R1, R2 & M1 in PRC-007, and (ii) the Applicability, Requirements and Measures sections in PRC-008. In addition, in certain instances (PRC-007 & -008), because independent system operators and regional transmission organizations are TOPs, the PRC-007 and PRC-008 may not be appropriately applied to these entities, because such entities do not own/operate UFLS.

The SAR should consider deleting PRC-009, and add the requirements to PRC-006-0 as R1.4.3.

KCP&L

The standards would be better organized by separating the reliability requirements from the supporting text that explains the requirements. Measures should then be applied only to the requirements and not the text.

Manitoba Hydro

PRC – 007:

- Purpose -If each standard included a list of all other closely related standards, the individual non-repeated purposes of related standards could be more easily compared by readers when necessary.
- Requirements – Shall Do What?
- R2 – "As necessary" should be removed. Annual updates of UFLS data to the RRO are necessary, even if they just only confirm that the previous year's data is still valid. Please refer to R3 comment below.

- R3 – Recommend further revision of R3. As well as RRO requested data within 30 days, there should be a mandatory requested annual update. This will coordinate with comment of R2.
- Measures - 2M for 3R.
- By making revisions to R2 and R3 as shown above, measure M2 will now appropriately cover both R2 and R3 for annual data updating and appropriate documentation transmission to RRO.

PRC-008-0:

Measure M1 needs to be revised to clearly reflect the measures applied to Requirement R1.

So. Company Transmission, Generation, and Alabama Power

Under PRC-006, Requirement 1.2, it is recommended the Regions have the responsibility for design details for determining Load Shedding Blocks (MWs), intentional and total tripping time delays, Generation protection, Islanding Schemes, Tie tripping schemes (within a Region), frequency set points (excludes BAL standard) and Load Restoration schemes. Also, the reporting of the time delay should only include the total time and not include the intentional time delay. The intentional time delay is included in the total time.

In PRC-006, Requirement 1.3, the Regional UFLS database is required to be updated at least every 5 years. However, under PRC-007, R2, the Transmission Owner is required to update its underfrequency data at least annually. These two timing update requirements should be consistent with one another.

In PRC-008 it is unclear how often the Transmission Owners are required to assess its maintenance and testing program. We recommend adding language to the SAR that says on a "as needed" basis.

Under PRC-008, Requirement 2, it states that Transmission Owner must implement its maintenance and testing program that is required in R1. It would seem more appropriate to include the implementation portion of R2 into R1 to say the Transmission Owner must have and implement a maintence and testing program.

The SAR drafting team should recognize that individual generator frequency trip set points are established by the manufacturer of the generator and not by the Generator Owner. Therefore, in the development of the underfrequency load shedding scheme, each Transmission Owner should recognize that these generator frequency trip settings cannot be adjusted and the load shedding schemes should take this into account. This standard should not require a Generator Owner to operate beyond the limits set by the manufacturer.

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NERC Region		**Registered Ballot Body Segment**
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PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

The standards in this set are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

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PRC-007 and PRC-009 have some "fill-in-the-blank" characteristics as identified in the Regional Reliability Standards Working Group work plan, which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards.

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Based on the comments received, the SAR drafting team revised the SAR for Project 2007-01, which includes:

1. PRC-008 was removed from the list of standards to be revised in association with Project 2007-01. The SAR drafting team agreed with a number of commenters that suggested grouping all the relay maintenance and testing standards into a single project. The SAR drafting team has requested that NERC staff remove PRC-008 from Project 2007-01 and place it in a project with the following standards:

    - PRC-005 (currently in Project 2008-04)
    - PRC-008 (currently in Project 2007-01)
    - PRC-011 (currently in Project 2008-02)
    - PRC-017 (currently in Project 2008-04)
    - PRC-018 Requirement 6 (currently in Project 2007-011)

2. The SAR was revised to clarify the scope of work to be performed on each standard including the addition of Appendix A to the SAR. The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed, "Issues to Consider"), nor are the items identified in the Issues to Consider mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. The SAR drafting team encourages all commenters to read Volume I of NERC's Three-year Reliability Standards Development Plan which identifies a set of specific issues each standard drafting team is to consider when revising a standard.

3. The Applicability section of the SAR was expanded to include Balancing Authority, Planning Authority/Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator. The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team will review the appropriate applicability of each of these standards.

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The UFLS SAR Drafting Team would like to receive industry comments on Draft 2 of the SAR for Project 2007-01. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.com with the words "UFLS SAR" in the subject line by **March 9, 2007.**

You do not have to answer all questions. Enter all comments in simple text format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☐ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☐ Yes

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   ☐ Yes

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   Comments:

Maureen E. Long
Standards Process Manager

February 8, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Comment Periods Open for three SARs

System Restoration and Blackstart SAR (February 8–March 9, 2007)

The second draft of the System Restoration and Blackstart SAR has been posted for a 30-day comment period from February 8 through March 9, 2007. The SAR calls for the modification of the following standards:

EOP-005 — System Restoration Plans
EOP-006 — Reliability Coordination – System Restoration
EOP-007 — Establish, Maintain, and Document a Regional Blackstart Capability Plan
EOP-009 — Documentation of Blackstart Generating Unit Test Results

This project involves upgrading the overall quality of the four standards; eliminating some gaps in the requirements, ambiguity, and "fill-in-the-blank" components.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards.

Please use the comment form to provide comments on this SAR.

Underfrequency Load Shedding SAR (February 8–March 9, 2007)

The second draft of the Underfrequency Load Shedding SAR has been posted for a 30-day comment period from February 8 through March 9, 2007. The SAR calls for the modification of the following standards:

PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs

PRC-007 — Assuring Consistency with Regional UFLS Programs

PRC-009 — UFLS Performance Following an Underfrequency Event

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Please use the comment form to provide comments on this SAR.

116-390 Village Boulevard, Princeton, New Jersey 08540-5721
Phone: 609.452.8060 ▪ Fax: 609.452.9550 ▪ www.nerc.com

Frequency Response SAR (February 8–March 9, 2007)

The third draft of the Frequency Response SAR has been posted for a 30-day comment period from February 8 through March 9, 2007. The SAR calls for the collection of data needed to model each interconnection's frequency response.

Please use the comment form to provide comments on this SAR.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Comment Form — 2nd Draft of SAR for Project 2007-11 Underfrequency Load Shedding

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Joe Springhetti	
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E-mail:	joseph.springhetti@we-energies.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☒ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Kathleen Goodman	
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E-mail:	kgoodman@iso-ne.com	
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   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Jason Shaver	
Organization:	American Transmission Co.	
Telephone:	262 506 6885	
E-mail:	jshaver@atcllc.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☒ **MRO** ☐ **NPCC** ☒ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
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The standards in this set are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team (SDT) will work with stakeholders to review PRC-006 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to and contained with the UFLS program documentation. The SDT shall determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 and PRC-009 have some "fill-in-the-blank" characteristics as identified in the Regional Reliability Standards Working Group work plan, which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards.

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1. PRC-008 was removed from the list of standards to be revised in association with Project 2007-01. The SAR drafting team agreed with a number of commenters that suggested grouping all the relay maintenance and testing standards into a single project. The SAR drafting team has requested that NERC staff remove PRC-008 from Project 2007-01 and place it in a project with the following standards:

    - PRC-005 (currently in Project 2008-04)
    - PRC-008 (currently in Project 2007-01)
    - PRC-011 (currently in Project 2008-02)
    - PRC-017 (currently in Project 2008-04)
    - PRC-018 Requirement 6 (currently in Project 2007-011)

2. The SAR was revised to clarify the scope of work to be performed on each standard including the addition of Appendix A to the SAR. The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed, "Issues to Consider"), nor are the items identified in the Issues to Consider mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. The SAR drafting team encourages all commenters to read Volume I of NERC's Three-year Reliability Standards Development Plan which identifies a set of specific issues each standard drafting team is to consider when revising a standard.

3. The Applicability section of the SAR was expanded to include Balancing Authority, Planning Authority/Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator. The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team will review the appropriate applicability of each of these standards.

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You do not have to answer all questions. Enter all comments in simple text format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: The standard should address both underfrequency and overfrequency, to avoid shedding too much load. The standard should also make it clear that generators must be well-protected, while still supporting the integrity of the system. Thus, Generators Owners must be part of the decision process when the regional entities establish the requirements for generators to remain on-line.

   Since it is possible that an island can be formed that envelopes more than one regional entitity, we recommend strong coordination between neighboring regions so that different and/or conflicting standards are not identified as resolution for a common island.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
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	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Bonneville Power Administration, Transmission Services

Lead Contact: **Mike Viles**

Contact Organization: **BPA**

Contact Segment: **1**

Contact Telephone: **360-418-2322**

Contact E-mail: **mrviles@bpa.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Gary Keenan	BPA	**WECC**	1

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following standards:

PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

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PRC-007 and PRC-009 have some "fill-in-the-blank" characteristics as identified in the Regional Reliability Standards Working Group work plan, which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

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    - PRC-005 (currently in Project 2008-04)
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2. The SAR was revised to clarify the scope of work to be performed on each standard including the addition of Appendix A to the SAR. The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed, "Issues to Consider"), nor are the items identified in the Issues to Consider mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. The SAR drafting team encourages all commenters to read Volume I of NERC's Three-year Reliability Standards Development Plan which identifies a set of specific issues each standard drafting team is to consider when revising a standard.

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments:

Comment Form — 2nd Draft of SAR for Project 2007-11 Underfrequency Load Shedding

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Steve Myers	
Organization:	ERCOT	
Telephone:	512-248-3077	
E-mail:	smyers@ercot.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
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Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: However, the drafting team should be encouraged to more clearly communicate that such Appendices are lists of topics and comments that are to be considered, but they are not lists of requirements that must be included in the standard to be developed.

3. Do you agree with expanding the Applicability section of the SAR to include Balancing Authority, Planning Authority or Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator so that the standard drafting team can consider these entities when reviewing the appropriate applicability of the standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Roger Champagne	
Organization:	Hydro-Québec TransÉnergie	
Telephone:	514 289-2211, X2766	
E-mail:	champagne.roger.2@hydro.qc.ca	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☒ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
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   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Ron Falsetti	
Organization:	IESO	
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E-mail:	ron.falsetti@ieso.ca	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☒ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
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	☐	5 — Electric Generators
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	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following standards:

PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

The standards in this set are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

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PRC-007 and PRC-009 have some "fill-in-the-blank" characteristics as identified in the Regional Reliability Standards Working Group work plan, which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards.

Draft 1 of this SAR was posted for a 30-day public comment period from November 29, 2006 through January 12, 2007. The Underfrequency Load Shedding SAR Drafting Team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 26 sets of comments, including comments from 70 different people from more than 25 companies representing 6 of the 10 industry segments.

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    - PRC-005 (currently in Project 2008-04)
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    - PRC-011 (currently in Project 2008-02)
    - PRC-017 (currently in Project 2008-04)
    - PRC-018 Requirement 6 (currently in Project 2007-011)

2. The SAR was revised to clarify the scope of work to be performed on each standard including the addition of Appendix A to the SAR. The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed, "Issues to Consider"), nor are the items identified in the Issues to Consider mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. The SAR drafting team encourages all commenters to read Volume I of NERC's Three-year Reliability Standards Development Plan which identifies a set of specific issues each standard drafting team is to consider when revising a standard.

3. The Applicability section of the SAR was expanded to include Balancing Authority, Planning Authority/Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator. The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team will review the appropriate applicability of each of these standards.

4. The SAR drafting team noted a number of comments suggesting additional topics or issues to consider with the refinement of the standards. These comments have been noted and added to the SAR for resolution during standard drafting.

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The UFLS SAR Drafting Team would like to receive industry comments on Draft 2 of the SAR for Project 2007-01. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.com with the words "UFLS SAR" in the subject line by **March 9, 2007.**

You do not have to answer all questions. Enter all comments in simple text format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments:

Comment Form — 2nd Draft of SAR for Project 2007-11 Underfrequency Load Shedding

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
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	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Standards Review Comittee

Lead Contact: **Charles Yeung**

Contact Organization: **SPP**

Contact Segment: **2**

Contact Telephone: **832-724-6142**

Contact E-mail: **cyeung@spp.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Alicia Daugherty	PJM	**RFC**	2
Mike Calimano	NYISO	**NPCC**	2
Ron Falsetti	IESO	**NPCC**	2
Matt Goldberg	ISO-NE	**NPCC**	2
Brent Kingsford	CAISO	**WECC**	2
Anita Lee	AESO	**WECC**	2
Steve Myers	ERCOT	**ERCOT**	2
Bill Phillips	MISO	**RFC+**	2
		+MRO	
		+SERC	

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

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PRC-007 and PRC-009 have some "fill-in-the-blank" characteristics as identified in the Regional Reliability Standards Working Group work plan, which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards.

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    - PRC-011 (currently in Project 2008-02)
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The UFLS SAR Drafting Team would like to receive industry comments on Draft 2 of the SAR for Project 2007-01. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.com with the words "UFLS SAR" in the subject line by **March 9, 2007.**

You do not have to answer all questions. Enter all comments in simple text format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☒ No

   Comments: The addition of Appendix A and Appendix C does not seem to improve clarity on the scope of work, but rather just add a list of "things to consider" for the standards drafting team. As it stands the scope of work is fairly wide open. However, we do not disagree that the standards drafting team should consider those comments.

3. Do you agree with expanding the Applicability section of the SAR to include Balancing Authority, Planning Authority or Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator so that the standard drafting team can consider these entities when reviewing the appropriate applicability of the standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☐ Yes

   ☐ No

   Comments:

Comment Form — 2nd Draft of SAR for Project 2007-11 Underfrequency Load Shedding

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Brian Thumm	
Organization:	ITC Holdings	
Telephone:	248.374.7846	
E-mail:	bthumm@itctransco.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☒ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☒ No

   Comments: None of the UFLS standards currently apply to either Planning function, and the SAR does not contemplate adding any requirements that do. The Planning Coordinator and the Transmission Planner should be removed from the scope of the SAR.

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: Independent transmission companies do not have direct access to load (location, nature, etc.) in order to fully implement a UFLS program. The applicability of the Standard should be further modified to reflect the need for the DP/LSE to own/operate/develop/maintain a UFLS program in cooperation with its TO/TOP/RC. The standard is currently written to allow the Regional Entity to require a Transmission Operator or Operator to own/operate a UFLS program, and, in general, an independent transmission company does not have the means to implement load shedding programs.

Comment Form — 2nd Draft of SAR for Project 2007-11 Underfrequency Load Shedding

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Michael Gammon	
Organization:	Kansas City Power & Light	
Telephone:	816-654-1242	
E-mail:	mike.gammon@kcpl.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with expanding the Applicability section of the SAR to include Balancing Authority, Planning Authority or Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator so that the standard drafting team can consider these entities when reviewing the appropriate applicability of the standards? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: Even though it is not mentioned in the question, the Reliability Coordinator should be included as one of the Applicable Entities. On the SAR the Reliability Authority is not checked in "The Standard will Apply to the Following Functions" table.

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments:

Comment Form — 2nd Draft of SAR for Project 2007-11 Underfrequency Load Shedding

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Robert Coish	
Organization:	Manitoba Hydro	
Telephone:	204-487-5479	
E-mail:	rgcoish@hydro.mb.ca	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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This project involves revising the requirements in the following standards:

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The standards in this set are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team (SDT) will work with stakeholders to review PRC-006 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to and contained with the UFLS program documentation. The SDT shall determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 and PRC-009 have some "fill-in-the-blank" characteristics as identified in the Regional Reliability Standards Working Group work plan, which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards.

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Based on the comments received, the SAR drafting team revised the SAR for Project 2007-01, which includes:

1. PRC-008 was removed from the list of standards to be revised in association with Project 2007-01. The SAR drafting team agreed with a number of commenters that suggested grouping all the relay maintenance and testing standards into a single project. The SAR drafting team has requested that NERC staff remove PRC-008 from Project 2007-01 and place it in a project with the following standards:

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    - PRC-011 (currently in Project 2008-02)
    - PRC-017 (currently in Project 2008-04)
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2. The SAR was revised to clarify the scope of work to be performed on each standard including the addition of Appendix A to the SAR. The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed, "Issues to Consider"), nor are the items identified in the Issues to Consider mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. The SAR drafting team encourages all commenters to read Volume I of NERC's Three-year Reliability Standards Development Plan which identifies a set of specific issues each standard drafting team is to consider when revising a standard.

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4. The SAR drafting team noted a number of comments suggesting additional topics or issues to consider with the refinement of the standards. These comments have been noted and added to the SAR for resolution during standard drafting.

5. Other miscellaneous changes as requested and agreed to by the SAR drafting team and identified in the redlined version of Draft 2 of the SAR for Project 2007-01.

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You do not have to answer all questions. Enter all comments in simple text format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: MH believes a lot of good effort has been put into the drafting of this SAR to identify all the significant issues that need to be considered in drafting the UFLS standards. The standard drafting team has its work cut out for it! - but at least, hopefully, all the significant issues are identified.

3. Do you agree with expanding the Applicability section of the SAR to include Balancing Authority, Planning Authority or Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator so that the standard drafting team can consider these entities when reviewing the appropriate applicability of the standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: Re-iterating significant comments made in 1st draft of SAR, but not included in MH comment section of Appendix C in 2nd draft:

   PRC – 007 – 0

   Measures.

M1 - If "consistency" is to be clarified here, it must also be clarified for R1 as well. If R1 does not require this clarification, neither does M1. Also, does "consistency" really require further clarification?

NEW COMMENTS FOR 2ND DRAFT.

Appendix C -

PJM Comments.

I believe RRO's should stand between regional UFLS owner/control areas and NERC. Various RRO's may have some different methodologies and procedures which are appropriate to their specific RRO regions and not to others. There should not be a single UFLS criteria from NERC that covers ALL UFLS conditions and concerns for the entire grid.

NCMPA Comments.

I agree with non-compulsory compliance for utilities with very low peak loads if they are surrounded by utilities with load levels sizable enough to require compliance to UFLS programs. However, if there are a lot of small load utilities in an RRO region whose total peak load is sizeable enough to require UFLS, these small utilities will have to coordinate as if they were one large utility in order to conform with their RRO's UFLS program in the same fashion a single large load utility would, to ensure proper total RRO region low frequency UFLS mitgation.

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NERC Region		**Registered Ballot Body Segment**
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Group Comments (Complete this page if comments are from a group.)

Group Name: Midwest ISO and individual stakeholders

Lead Contact: **Jason Marshall**

Contact Organization: **Midwest ISO**

Contact Segment: **2**

Contact Telephone: **(317) 249-5494**

Contact E-mail: **jmarshall@midwestiso.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Brian F. Thumm	ITC	**RFC**	1
Jim Cyrulewski	JDRJC Associates	**RFC**	8

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1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: In general, we agree with the inclusion of Appendix A and the relevant comments that are included in Appendix C. However, we have the following specific issues with regard to the comments in Appendix C. On Page C-2, we do not agree with KCP&L's assertion that all compliance programs are administered by Reliability Coordinators. Reliability Coordinators do not administer compliance programs. Additionally, we are concerned with the meaning of Manitoba Hydro's general comment on Page C-3 that the RA needs to be included. We are assuming they mean Reliability Coordinator. We do not oppose the Reliability Coordinator being included to the extent they are made aware and have the settings of the UFLS relays available to them; however, we clearly do not believe the Reliability Coordinator should have any coordination role or should replace the role of the RRO.

3. Do you agree with expanding the Applicability section of the SAR to include Balancing Authority, Planning Authority or Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator so that the standard drafting team can consider these entities when reviewing the appropriate applicability of the standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: Is Planning Authority still in the functional model? We believe this function has been replaced.

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☒ Yes

   ☐ No

Comments: In general, this SAR is much improved. We do support ATC's assertion on Page C-4 of Appendix C that the SDT should consider generation frequency response. We ask that they coordinate with the Frequency Response SAR drafting team.

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Group Comments (Complete this page if comments are from a group.)

Group Name: NPCC CP9, Reliability Standards Working Group

Lead Contact: **Guy V. Zito**

Contact Organization: **Northeast Power Coordinating Council**

Contact Segment: **10**

Contact Telephone: **212-840-1070**

Contact E-mail: **gzito@npcc.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Kathleen Goodman	ISO- New England	**NPCC**	2
Bill Shemley	ISO- New England	**NPCC**	2
Greg Campoli	New York ISO	**NPCC**	2
Al Adamson	New York State Rel. Council	**NPCC**	10
Randy McDonald	New Brunswick System Operator	**NPCC**	2
Roger Champagne	TransEnergie HydroQuebec	**NPCC**	1
Bruno Jesus	Hydro One Networks	**NPCC**	1
Ron Falsetti	The IESO, Ontario	**NPCC**	2
Herb Schrayshuen	National Grid US	**NPCC**	1
Donald Nelson	MA Dept. of Tele. and Energy	**NPCC**	9
Ralph Rufrano	New York Power Authority	**NPCC**	1
Murale Gopinathan	Northeast Utilities	**NPCC**	1
Jerad Barnhart	NStar	**NPCC**	1
Guy V. Zito	NPCC	**NPCC**	10
Ed Tompson	ConEd	**NPCC**	1

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   ☒ Yes

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   Comments:

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   ☒ Yes

   ☐ No

   Comments: We agree with the additional functions proposed in the Applicability section to allow the drafting team the ability to fully consider any entities that may have a role in the standard, also the entities need to be updated to match the latest version of the Functional Model.

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☐ Yes

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   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Michael Calimano	
Organization:	New York Independent System Operator	
Telephone:	(518) 356 - 6129	
E-mail:	mcalimano@nyiso.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☒ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
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PRC-007 and PRC-009 have some "fill-in-the-blank" characteristics as identified in the Regional Reliability Standards Working Group work plan, which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards.

Draft 1 of this SAR was posted for a 30-day public comment period from November 29, 2006 through January 12, 2007. The Underfrequency Load Shedding SAR Drafting Team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 26 sets of comments, including comments from 70 different people from more than 25 companies representing 6 of the 10 industry segments.

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1. PRC-008 was removed from the list of standards to be revised in association with Project 2007-01. The SAR drafting team agreed with a number of commenters that suggested grouping all the relay maintenance and testing standards into a single project. The SAR drafting team has requested that NERC staff remove PRC-008 from Project 2007-01 and place it in a project with the following standards:

    - PRC-005 (currently in Project 2008-04)
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    - PRC-011 (currently in Project 2008-02)
    - PRC-017 (currently in Project 2008-04)
    - PRC-018 Requirement 6 (currently in Project 2007-011)

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The UFLS SAR Drafting Team would like to receive industry comments on Draft 2 of the SAR for Project 2007-01. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.com with the words "UFLS SAR" in the subject line by **March 9, 2007.**

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: The addition of Appendix A and Appendix C does not seem to improve clarity on the scope of work, but rather just add a list of "things to consider" for the standards drafting team. As it stands the scope of work is fairly wide open. However, we do not disagree that the standards drafting team should consider those comments.

3. Do you agree with expanding the Applicability section of the SAR to include Balancing Authority, Planning Authority or Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator so that the standard drafting team can consider these entities when reviewing the appropriate applicability of the standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments:

Comment Form — 2nd Draft of SAR for Project 2007-11 Underfrequency Load Shedding

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
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	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Pepco Holdings, Inc. - Affiliates

Lead Contact: **Richard Kafka**

Contact Organization: **Pepco Holdings, Inc.**

Contact Segment: **1**

Contact Telephone: **301-469-5274**

Contact E-mail: **rjkafka@pepcoholdings.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Alvin Depew	Potomac Electric Power Co	**RFC**	1
Carl Kinsley	Delmarva Power & Light	**RFC**	1
Evan Sage	Potomac Electric Power Co	**RFC**	1

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following standards:

PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

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The UFLS SAR Drafting Team would like to receive industry comments on Draft 2 of the SAR for Project 2007-01. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.com with the words "UFLS SAR" in the subject line by **March 9, 2007.**

You do not have to answer all questions. Enter all comments in simple text format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: PHI concurs that relay maintenance standards should be consolidated.

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments:

Comment Form — 2nd Draft of SAR for Project 2007-11 Underfrequency Load Shedding

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: SERC EC Planning Standards Subcommittee

Lead Contact: **Travis Sykes**

Contact Organization: **Tennessee Valley Authority**

Contact Segment: **1**

Contact Telephone: **423-751-4162**

Contact E-mail: **tssykes@tva.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Darrell Pace	Alabama Electric Coooperative	**SERC**	1
John Sullivan	Ameren	**SERC**	1
Bob McGarrah	Ameren	**SERC**	1
Charles Long	Entergy	**SERC**	1
David Weekley	MEAG Power	**SERC**	1
Pat Huntley	SERC Reliability Corp	**SERC**	10
Phil Kleckley	SC Electric and Gas	**SERC**	3
Bob Jones	Southern Company Services	**SERC**	1
Brian Moss	Duke Energy Carolinas	**SERC**	1

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

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   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments: The PSS does not see a reason for including the BA, GO, and GOP, but has no objections to allowing the SDT to consider these entities.

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Fred J. Frederick	
Organization:	Vectren Energy Delivery	
Telephone:	812-491-4570	
E-mail:	ffrederick@vectren.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☒ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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   ☐ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☐ No

   Comments:

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: UFLS steps should be set with a considerable amount of bandwidth. That is if there are 5 steps of 5% required, an enitiy could drop as much as say 10% in the first step and possibly drop as little as 1% in the second step. As long as the cumulative amount is within the requirements of that level of steps (5-10-15-20-25%). Trying to meet an exact amount of load drop is very difficult and would not provide enough benefit to justify the cost.

Comment Form — 2nd Draft of SAR for Project 2007-11 Underfrequency Load Shedding

Please use this form to submit comments on Draft 2 of the SAR for Project 2007-01, Underfrequency Load Shedding (UFLS). Comments must be submitted by **March 9, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "UFLS SAR" in the subject line. If you have questions please contact David Taylor at dave.taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: NERC System Protection and Control Task Force

Lead Contact: **Charles Rogers**

Contact Organization: **Consumers Energy**

Contact Segment:

Contact Telephone: **517-788-0027**

Contact E-mail: **cwrogers@cmsenergy.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
W Mark Carpenter	TXU Energy Delivery	**ERCOT**	
David Angell	Idaho Power	**WECC**	
Deven Bhan	WAPA	**MRO**	
Joseph Burdis	PJM	**RFC**	
John Ciufo	Hydro One	**NPCC**	
Jim Ingeson	NYISO	**NPCC**	
Mike McDonald	Ameren	**SERC**	
William Miller	Exelon	**RFC**	
John Mulhausen	Florida Power and Light	**FRCC**	
James Roberts	TVA	**SERC**	
Evan Sage	PEPCO	**RFC**	
Jon Sykes	Salt River Project	**WECC**	
Phil Tatro	National Grid	**NPCC**	
Joe Uchiyama	US Bureau of Reclamation	**WECC**	
Eric Udren	KEMA		
Tom Wiedman	Wiedman Consulting		
Philip Winston	Georgia Power	**SERC**	
Baj Agrawal	Arizona Public Service	**WECC**	
Henry Miller	AEP	**RFC**	
Robert Cummings	NERC Staff		
Dean Sikes	CLECO	**SPP**	
Robert Stuart	Elequant	**WECC**	

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following standards:

PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

The standards in this set are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team (SDT) will work with stakeholders to review PRC-006 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to and contained with the UFLS program documentation. The SDT shall determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 and PRC-009 have some "fill-in-the-blank" characteristics as identified in the Regional Reliability Standards Working Group work plan, which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high-quality, enforceable, and technically sufficient bulk power system reliability standards.

Draft 1 of this SAR was posted for a 30-day public comment period from November 29, 2006 through January 12, 2007. The Underfrequency Load Shedding SAR Drafting Team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 26 sets of comments, including comments from 70 different people from more than 25 companies representing 6 of the 10 industry segments.

Based on the comments received, the SAR drafting team revised the SAR for Project 2007-01, which includes:

1. PRC-008 was removed from the list of standards to be revised in association with Project 2007-01. The SAR drafting team agreed with a number of commenters that suggested grouping all the relay maintenance and testing standards into a single project. The SAR drafting team has requested that NERC staff remove PRC-008 from Project 2007-01 and place it in a project with the following standards:

    - PRC-005 (currently in Project 2008-04)
    - PRC-008 (currently in Project 2007-01)
    - PRC-011 (currently in Project 2008-02)
    - PRC-017 (currently in Project 2008-04)
    - PRC-018 Requirement 6 (currently in Project 2007-011)

2. The SAR was revised to clarify the scope of work to be performed on each standard including the addition of Appendix A to the SAR. The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed, "Issues to Consider"), nor are the items identified in the Issues to Consider mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. The SAR drafting team encourages all commenters to read Volume I of NERC's Three-year Reliability Standards Development Plan which identifies a set of specific issues each standard drafting team is to consider when revising a standard.

3. The Applicability section of the SAR was expanded to include Balancing Authority, Planning Authority/Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator. The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team will review the appropriate applicability of each of these standards.

4. The SAR drafting team noted a number of comments suggesting additional topics or issues to consider with the refinement of the standards. These comments have been noted and added to the SAR for resolution during standard drafting.

5. Other miscellaneous changes as requested and agreed to by the SAR drafting team and identified in the redlined version of Draft 2 of the SAR for Project 2007-01.

The UFLS SAR Drafting Team would like to receive industry comments on Draft 2 of the SAR for Project 2007-01. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.com with the words "UFLS SAR" in the subject line by **March 9, 2007.**

You do not have to answer all questions. Enter all comments in simple text format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The SPCTF has developed a report which provides a technical assessment of all three of these standards, which is attached. Please include the observations from this report in the scope of work on these standards.

3. Do you agree with expanding the Applicability section of the SAR to include Balancing Authority, Planning Authority or Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator so that the standard drafting team can consider these entities when reviewing the appropriate applicability of the standards? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: Please see the comments in the attached SPCTF report for the SPCTFs position on the applicable entities.

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments:

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Group Comments (Complete this page if comments are from a group.)

Group Name: Southern Company Transmission

Lead Contact: **Roman Carter**

Contact Organization: **Southern Company Transmission**

Contact Segment: **Transmission Owner**

Contact Telephone: **205.257.6027**

Contact E-mail: **jrcarter@southernco.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Jonathan Glidewell	Southern Co. Transmission	**SERC**	1
Marc Butts	Southern Co. Transmission	**SERC**	1
JT Wood	Southern Co. Transmission	**SERC**	1
Jim Busbin	Southern Co. Transmission	**SERC**	1
Barry Dyer	Alabama Power Company	**SERC**	3
Phil Winston	Georgia Power Company	**SERC**	3

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2. The SAR was revised to clarify the scope of work to be performed on each standard including the addition of Appendix A to the SAR. The scope of the SAR is designed to provide the standard drafting team with sufficient flexibility to address all necessary revisions. Work is not to be limited to the "To Do List" (renamed, "Issues to Consider"), nor are the items identified in the Issues to Consider mandatory revisions. A unique development aspect of the projects included in NERC's three-year reliability standards development plan is that the standard drafting teams will not be inhibited from addressing at one time all necessary improvements to the standards, or from even proposing new changes to the standard, as long as the changes are within the content area of the standard. The goal is for the drafting team to develop the best possible standard within the defined subject area, as supported by a consensus of stakeholders. The SAR drafting team encourages all commenters to read Volume I of NERC's Three-year Reliability Standards Development Plan which identifies a set of specific issues each standard drafting team is to consider when revising a standard.

3. The Applicability section of the SAR was expanded to include Balancing Authority, Planning Authority/Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator. The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team will review the appropriate applicability of each of these standards.

4. The SAR drafting team noted a number of comments suggesting additional topics or issues to consider with the refinement of the standards. These comments have been noted and added to the SAR for resolution during standard drafting.

5. Other miscellaneous changes as requested and agreed to by the SAR drafting team and identified in the redlined version of Draft 2 of the SAR for Project 2007-01.

The UFLS SAR Drafting Team would like to receive industry comments on Draft 2 of the SAR for Project 2007-01. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.com with the words "UFLS SAR" in the subject line by **March 9, 2007.**

You do not have to answer all questions. Enter all comments in simple text format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with expanding the Applicability section of the SAR to include Balancing Authority, Planning Authority or Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator so that the standard drafting team can consider these entities when reviewing the appropriate applicability of the standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: Southern does not object to the Standard Drafting team considering the BA, GO, and GOP in the applicability section. However, only after the requirements of the future standard are developed should a final determination be made on the applicability.

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: We have a general concern with the ambiguity associated with the violation severity levels. For example, Moderate and High severity levels both state that an entity is deficient in one or more significant elements. It would seem reasonable that High severity would mean you were deficient in multiple (at least greater than one) significant elements and not just in one element as moderate states.

   Are we to interpret a significant element is to mean a standard requirement? What are examples of a significant element other than a requirement contained in the standard?

Finally, we have a general comment about the SAR development process as a whole. FERC is concerned with the amount of time it takes NERC (through the ANSI accredited process) to develop a standard. Since the SAR development process only outlines the scope of the future standard development (in other words, there are no requirements to a SAR), it is recommended that the NERC standards development process accelerate through the SAR phase in order to initiate the more complex task of developing the requirements of a particular Standard. In other words, there should only be, at most, two rounds of comments for a SAR prior to it shifting to the standards drafting team.

Consideration of Comments on 2nd Posting of Underfrequency Load Shedding SAR

The Underfrequency Load Shedding (UFLS) SAR drafting team thanks all commenters who submitted comments on Draft 2 of the UFLS SAR. This SAR was posted for a 30-day public comment period from **February 8 through March 9, 2007**. The SAR drafting team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 19 sets of comments received, including comments from more than 78 different people from 55 organizations representing 9 of the 10 industry segments as shown in the table on the following pages.

The SAR drafting team recommends that the Standards Committee accept the revised SAR for Project 2007-01 UFLS for development as a standard.

Based on comments received on the second posting of this SAR for comment the SAR drafting team revised the Applicability section of the SAR to include Reliability Coordinator and updated the Applicability section to reflect the latest version of the SAR form. It was noted by the SAR drafting team that the "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard and that the standard drafting team is to review the appropriate applicability of the standard. Finally, the SAR drafting team noted a number of comments outside the scope of responsibility of the SAR drafting team to resolve which will be forwarded to the standard drafting team for consideration.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Underfrequency_Load_Shedding.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Henry Miller (G6)	AEP										
2.	Anita Lee (G1)	AESO		✓								
3.	Darrell Pace	Alabama Electric Coop.	✓									
4.	Barry Dyer (G7)	Alabama Power Company			✓							
5.	John Sullivan	Ameren	✓									
6.	Bob McGarrah	Ameren	✓									
7.	Mike McDonald (G6)	Ameren										
8.	Jason Shaver	American Transmission Co.	✓									
9.	Baj Agrawal (G6)	Arizona Public Service										
10.	Mike Viles	BPA	✓									
11.	Gary Keenan	BPA	✓									
12.	Brent Kingsford (G1)	CAISO		✓								
13.	Dean Sikes (G6)	CLECO										
14.	Charles Rogers (G6)	Comsumers Energy										
15.	Ed Thompson	ConEd	✓									
16.	Carl Kinsley (G4)	Delmarva Power & Light	✓									
17.	Brian Moss	Duke Energy Carolinas	✓									
18.	Robert Stuart (G6)	Elequant										
19.	Charles Long	Entergy	✓									
20.	Steve Myers (G1)	ERCOT		✓								
21.	William Miller (G6)	Exelon										
22.	John Muklhausen (G6)	FPL										
23.	Philip Winston (G6) (G7)	Georgia Power Company			✓							
24.	John Ciufo (G6)	Hydro One										
25.	Bruno Jesus (G2)	Hydro One Networks, Inc.	✓									
26.	David Angell (G6)	Idaho Power										
27.	Ron Falsetti (G1)	IESO		✓								
28.	Matt Goldberg (G1)	ISO New England		✓								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
29.	Kathleen Goodman (G1)	ISO New England		✓								
30.	Bill Shemley (G2)	ISO New England		✓								
31.	Brian Thumm (G1)	ITC Holdings	✓									
32.	Jim Cyrulewski (G3)	JDRJC Associates								✓		
33.	Michael Gammon	KCPL	✓									
34.	Eric Udren (G6)	KEMA										
35.	Don Nelson (G2)	MA Dept. of Tele. And Energy									✓	
36.	Robert Coish	Manitoba Hydro	✓		✓		✓	✓				
37.	David Weekley	MEAG Power	✓									
38.	Jason Marshall (G3)	Midwest ISO Stakeholders Standards Collaboration Participants		✓								
39.	Brian F. Thumm (G3)	Midwest ISO Stakeholders Standards Collaboration Participants		✓								
40.	Jim Cyrulewski (G3)	Midwest ISO Stakeholders Standards Collaboration Participants								✓		
41.	Bill Phillips (G1)	MISO		✓								
42.	Phil Tatro (G6)	National Grid										
43.	Randy MdDonald (G2)	NBSO		✓								
44.	Robert Cummings (G6)	NERC Staff										
45.	Herb Schrayshuen (G2)	NGrid	✓									
46.	Guy V. Zito (G2)	NPCC										✓
47.	Jerad Barnhart (G2)	NStar	✓									
48.	Murale Gopinathan (G2)	NU	✓									
49.	Mike Calimano (G1)	NYISO		✓								
50.	Greg Campoli (G2)	NYISO		✓								
51.	Jim Ingelson (G6)	NYISO										
52.	Ralph Rufrano (G2)	NYPA	✓									
53.	Al Adamson (G2)	NYSRC		✓								
54.	Evan Sage (G6)	Pepco										
55.	Richard Kafka (G4)	Pepco Holdings, Inc.										
56.	Alicia Daughtery (G1)	PJM		✓								
57.	Joseph Burdis (G6)	PJM										
58.	Alvin Depew (G4)	Potomac Electric Power Co.	✓									
59.	Evan Sage (G4)	Potomac Electric Power Co.	✓									
60.	Phil Kleckley	SC Electric and Gas			✓							
61.	Pat Huntley	SERC Reliability Corp.										✓
62.	Bob Jones	Southern Company Services, Inc.	✓									
63.	Roman Carter (G7)	Southern Company Transmission	✓									
64.	Jonathan Glidewell (G7)	Southern Company Transmission	✓									
65.	Marc Butts (G7)	Southern Company Transmission	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
66.	JT Wood (G7)	Southern Company Transmission	✓									
67.	Jim Busbin (G7)	Southern Company Transmission	✓									
68.	Charles Yeung (G1)	SPP		✓								
69.	Jon Sykes (G6)	SRP										
70.	Roger Champagne (G2) (I)	TransÉnergie Hydro-Québec	✓									
71.	Travis Sykes	TVA	✓									
72.	James Roberts (G6)	TVA										
73.	W. Mark Carpenter (G6)	TXU Energy Delivery										
74.	Joe Uchiyama (G6)	U.S. Bureau of Reclamation										
75.	Fred J. Frederick	Vectren Energy Delivery										
76.	Deven Bhan (G6)	WAPA										
77.	Howard Rulf	We Energies			✓	✓	✓					
78.	Tom Wiedman (G6)	Wiedman Consulting										

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 - IRC Standards Review Committee
G2 – NPCC CP9 Reliability Standards Working Group (NPCC CP9)
G3 – Midwest ISO Stakeholders Standards Collaboration Participants (MISO SSC)
G4 – Pepco Holdings, Inc. – Affiliates
G5 – SERC PC Planning Standards Subcommittee
G6 – NERC System Protection and Control Task Force
G7 – Southern Company Transmission

Index to Questions, Comments, and Responses

1. **Do you agree that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01 and placed into a project with all the relay maintenance and testing standards? If not, please explain in the comment area.**

Summary Consideration: Every commenter agreed that PRC-008 should be removed from the list of standards to be revised in association with Project 2007-01.

Question #1			
Commenter	**Yes**	**No**	**Comment**
We Energies	☑		
ATC LLC	☑		
BPA	☑		
ERCOT	☑		
HQT	☑		
IESO	☑		
IRC	☑		
ISO-NE	☑		
ITC Holdings	☑		
KCPL	☑		
Manitoba Hydro	☑		
MISO SCC	☑		
NPCC CP9 RSWG	☑		
NYISO	☑		
Pepco	☑		PHI concurs that relay maintenance standards should be consolidated.
SERC PSS	☑		
Southern Company Transmission	☑		
SPCTF	☑		

2. Do you agree with revising the SAR to clarify the scope of work to be performed on each standard including the addition of Appendix A and Appendix C to the SAR? If not, please explain in the comment area.

Summary Consideration: Most commenters agree with the revised scope. Note that the drafting team will forward additional comments recommending specific technical changes to the standards, to the standard drafting team.

Question #2			
Commenter	**Yes**	**No**	**Comment**
SPCTF		☑	The SPCTF has developed a report which provides a technical assessment of all three of these standards, which is attached. Please include the observations from this report in the scope of work on these standards.
Response: SPCTF's report will be forwarded to the standard drafting team for their consideration.			
MISO SCC		☑	In general, we agree with the inclusion of Appendix A and the relevant comments that are included in Appendix C. However, we have the following specific issues with regard to the comments in Appendix C. On Page C-2, we do not agree with KCP&L's assertion that all compliance programs are administered by Reliability Coordinators. Reliability Coordinators do not administer compliance programs. Additionally, we are concerned with the meaning of Manitoba Hydro's general comment on Page C-3 that the RA needs to be included. We are assuming they mean Reliability Coordinator. We do not oppose the Reliability Coordinator being included to the extent they are made aware and have the settings of the UFLS relays available to them; however, we clearly do not believe the Reliability Coordinator should have any coordination role or should replace the role of the RRO.
Response: The standard drafting team will review all comments identified in Appendix C of the SAR and make recommendations accordingly. The standard drafting team's recommendations will posted for public comment at which time the MISO SCC can review and comment further.			
IRC	☑	☑	The addition of Appendix A and Appendix C does not seem to improve clarity on the scope of work, but rather just add a list of "things to consider" for the standards drafting team. As it stands the scope of work is fairly wide open. However, we do not disagree that the standards drafting team should consider those comments.

Question #2			
Commenter	**Yes**	**No**	**Comment**
Response: The scope of the SAR is designed to provide the standard drafting team with a high degree of flexibility for revising the existing standards. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard.			
NYISO	☑		The addition of Appendix A and Appendix C does not seem to improve clarity on the scope of work, but rather just add a list of "things to consider" for the standards drafting team. As it stands the scope of work is fairly wide open. However, we do not disagree that the standards drafting team should consider those comments.
Response: The scope of the SAR is designed to provide the standard drafting team with a high degree of flexibility for revising the existing standards. Volume I of NERC's three-year reliability standards development plan identifies a set of specific issues each standard drafting team is to consider when revising a standard.			
ERCOT	☑		However, the drafting team should be encouraged to more clearly communicate that such Appendices are lists of topics and comments that are to be considered, but they are not lists of requirements that must be included in the standard to be developed.
Response: The SAR drafting team agrees with the comment.			
Manitoba Hydro	☑		MH believes a lot of good effort has been put into the drafting of this SAR to identify all the significant issues that need to be considered in drafting the UFLS standards. The standard drafting team has its work cut out for it! - but at least, hopefully, all the significant issues are identified.
We Energies	☑		
ATC LLC	☑		
BPA	☑		
HQT	☑		
IESO	☑		
ISO-NE	☑		

Question #2			
Commenter	**Yes**	**No**	**Comment**
ITC Holdings	☑		
KCPL	☑		
NPCC CP9 RSWG	☑		
Pepco	☑		
SERC PSS	☑		
Southern Company Transmission	☑		

3. **Do you agree with expanding the Applicability section of the SAR to include Balancing Authority, Planning Authority or Planning Coordinator, Transmission Planner, Generator Owner, and Generator Operator so that the standard drafting team can consider these entities when reviewing the appropriate applicability of the standards? If not, please explain in the comment area.**

Summary Consideration: Most commenters agreed with the applicability section of the SAR – however a commenter suggested adding the Reliability Coordinator as a potential responsible entity, and the drafting team did make that modification and some commenters indicated that the SAR Form did not reference the latest names for functional entities and the drafting team has updated the SAR Form to use the terms from Version 3 of the Functional Model.

Question #3			
Commenter	**Yes**	**No**	**Comment**
SPCTF		☑	Please see the comments in the attached SPCTF report for the SPCTFs position on the applicable entities.
Response: SPCTF's report will be forwarded to the standard drafting team for their consideration.			
ITC Holdings		☑	None of the UFLS standards currently apply to either Planning function, and the SAR does not contemplate adding any requirements that do. The Planning Coordinator and the Transmission Planner should be removed from the scope of the SAR.
Response: The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team will review the applicability section of the standard and make a recommendation accordingly. Therefore the SAR drafting team does not agree with removing the Planning Coordinator and the Transmission Planner from the Applicability section.			
KCPL		☑	Even though it is not mentioned in the question, the Reliability Coordinator should be included as one of the Applicable Entities. On the SAR the Reliability Authority is not checked in "The Standard will Apply to the Following Functions" table.
Response: The SAR drafting team added Reliability Coordinator as a potential functional entity the revised standard might apply to.			
MISO SCC	☑		Is Planning Authority still in the functional model? We believe this function has been replaced.

Question #3			
Commenter	**Yes**	**No**	**Comment**
Response: The drafting team agrees and the standard drafting team will be required to use the latest version of the functional model.			
NPCC CP9 RSWG	☑		We agree with the additional functions proposed in the Applicability section to allow the drafting team the ability to fully consider any entities that may have a role in the standard, also the entities need to be updated to match the latest version of the Functional Model.
Response: The drafting team agrees and has transferred the information to the latest version of the SAR form.			
SERC PSS	☑		The PSS does not see a reason for including the BA, GO, and GOP, but has no objections to allowing the SDT to consider these entities.
Response: The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team will review the applicability section of the standard and make a recommendation accordingly.			
Southern Company Transmission	☑		Southern does not object to the Standard Drafting team considering the BA, GO, and GOP in the applicability section. However, only after the requirements of the future standard are developed should a final determination be made on the applicability.
Response: The "applicability" identified in the SAR is the starting point for consideration of redrafting of the standard. The standard drafting team will review the applicability section of the standard and make a recommendation accordingly.			
We Energies	☑		
ATC LLC	☑		
BPA	☑		
ERCOT	☑		
HQT	☑		
IESO	☑		

Question #3			
Commenter	**Yes**	**No**	**Comment**
IESO	☑		
IRC	☑		
ISO-NE	☑		
Manitoba Hydro	☑		
NYISO	☑		
Pepco	☑		

4. Do you have any other concerns with the revisions made to the SAR? If yes, please explain in the comment area.

Summary Consideration: Most commenters did not have any other concerns with the revisions made to the SAR. Several commenters suggested technical revisions for consideration during standard development and these suggestions will be forwarded to the standard drafting team.

Question #4			
Commenter	**Yes**	**No**	**Comment**
ATC LLC	☑		The standard should address both underfrequency and overfrequency, to avoid shedding too much load. The standard should also make it clear that generators must be well-protected, while still supporting the integrity of the system. Thus, Generators Owners must be part of the decision process when the regional entities establish the requirements for generators to remain on-line. Since it is possible that an island can be formed that envelopes more than one regional entity, we recommend strong coordination between neighboring regions so that different and/or conflicting standards are not identified as resolution for a common island.
Response: The SAR drafting team will forward ATC LLC's comments to the standard drafting team for their consideration.			
ITC Holdings	☑		Independent transmission companies do not have direct access to load (location, nature, etc.) in order to fully implement a UFLS program. The applicability of the Standard should be further modified to reflect the need for the DP/LSE to own/operate/develop/maintain a UFLS program in cooperation with its TO/TOP/RC. The standard is currently written to allow the Regional Entity to require a Transmission Operator or Operator to own/operate a UFLS program, and, in general, an independent transmission company does not have the means to implement load shedding programs.
Response: The SAR drafting team will forward ITC Holdings' comments to the standard drafting team for their consideration.			
Vectren	☑		UFLS steps should be set with a considerable amount of bandwidth. That is if there are 5 steps of 5% required, an entity could drop as much as say 10% in the first step and possibly drop as little as 1% in the second step. As long as the cumulative amount is within the requirements of that level of steps (5-10-15-20-25%). Trying to meet an exact amount of load drop is very difficult and would not provide enough benefit to

Question #4			
Commenter	**Yes**	**No**	**Comment**
			justify the cost.
Response: The SAR drafting team will forward Vectren's comments to the standard drafting team for their consideration.			
MISO SCC	☑		In general, this SAR is much improved. We do support ATC's assertion on Page C-4 of Appendix C that the SDT should consider generation frequency response. We ask that they coordinate with the Frequency Response SAR drafting team.
Response: The SAR drafting team will forward MISO SCC's comments to the standard drafting team for their consideration.			
Manitoba Hydro	☑		Re-iterating significant comments made in 1st draft of SAR, but not included in MH comment section of Appendix C in 2nd draft: PRC – 007 – 0 Measures. M1 - If "consistency" is to be clarified here, it must also be clarified for R1 as well. If R1 does not require this clarification, neither does M1. Also, does "consistency" really require further clarification? NEW COMMENTS FOR 2ND DRAFT. Appendix C - **PJM Comments.** I believe RRO's should stand between regional UFLS owner/control areas and NERC. Various RRO's may have some different methodologies and procedures which are appropriate to their specific RRO regions and not to others. There should not be a single UFLS criteria from NERC that covers ALL UFLS conditions and concerns for the entire grid. **NCMPA Comments.** I agree with non-compulsory compliance for utilities with very low peak loads if they are

Question #4			
Commenter	**Yes**	**No**	**Comment**
			surrounded by utilities with load levels sizable enough to require compliance to UFLS programs. However, if there are a lot of small load utilities in an RRO region whose total peak load is sizeable enough to require UFLS, these small utilities will have to coordinate as if they were one large utility in order to conform with their RRO's UFLS program in the same fashion a single large load utility would, to ensure proper total RRO region low frequency UFLS mitgation.
Response: The SAR drafting team will forward MH's comments to the standard drafting team for their consideration.			
Southern Company Transmission	☑		We have a general concern with the ambiguity associated with the violation severity levels. For example, Moderate and High severity levels both state that an entity is deficient in one or more significant elements. It would seem reasonable that High severity would mean you were deficient in multiple (at least greater than one) significant elements and not just in one element as moderate states. Are we to interpret a significant element is to mean a standard requirement? What are examples of a significant element other than a requirement contained in the standard? Finally, we have a general comment about the SAR development process as a whole. FERC is concerned with the amount of time it takes NERC (through the ANSI accredited process) to develop a standard. Since the SAR development process only outlines the scope of the future standard development (in other words, there are no requirements to a SAR), it is recommended that the NERC standards development process accelerate through the SAR phase in order to initiate the more complex task of developing the requirements of a particular Standard. In other words, there should only be, at most, two rounds of comments for a SAR prior to it shifting to the standards drafting team.
Response: The SAR drafting team will forward Southern Company Transmission's comments contained in the first two paragraphs above to the standard drafting team for their consideration. With respect to the last paragraph, this is outside the scope of the SAR drafting team's responsibility.			
We Energies		☑	

Question #4			
Commenter	**Yes**	**No**	**Comment**
BPA		☑	
ERCOT		☑	
HQT		☑	
IESO		☑	
IRC		☑	
ISO-NE		☑	
KCPL		☑	
NPCC CP9 RSWG		☑	
NYISO		☑	
Pepco		☑	
SERC PSS		☑	
SPCTF		☑	

Standard Authorization Request Form

Title of Proposed Standard **Project 2007-01**	**Underfrequency Load Shedding (UFLS) Standards**
Request Date **Revised**	**November 14, 2006** **March 28, 2007**

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)
Name Regional Reliability Standards Working Group	☐ New Standard
Primary Contact **Robert W. Millard** **Director of Standards** **ReliabilityFirst Corporation**	☒ Revision to existing Standards PRC-006, PRC-007, and PRC-009
Telephone (630) 261-2621 **Fax (630) 691-4222**	☐ Withdrawal of existing Standard
E-mailbob.millard@rfirst.org	☐ Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

PRC-006— Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
PRC-009 — UFLS Performance Following an Underfrequency Event

The purpose of revising the above standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems – ensure each of the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties - the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Incorporate other general improvements described in NERC's Reliability Standards Development Plan: 2007-2009 (summarized and outlined in the Reliability Standard Review Guidelines attached as Appendix A).
4. Consider the items mentioned in the Standard Review Forms (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) attached as Appendix B, prepared by the NERC staff, which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006) ,
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,
    - Version 0 standards development (see note 1), and
    - Regional Fill-in-the-Blank Team (RRSWG – a NERC working group involved with regional standards development).

    The standard drafting team should also consider any other issues that were not completely captured but were stated or referenced in the above materials.
5. Consider issues raised by the industry during the posting of the SAR for Project 2007-01 during the first comment period from November 29, 2006 through January 12, 2007, attached as Appendix C.
6. Satisfy the standards procedure requirement for five-year review of the standards.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

The standards in this set are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to stand up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team (SDT) will work with stakeholders to review PRC-006 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to and contained with the UFLS program documentation. The SDT shall determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 and PRC-009 have some 'fill-in-the-blank' characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	**Reliability Coordinator**	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	**Balancing Authority**	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	**Interchange Coordinator**	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.

☒	**Planning Coordinator**	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	**Resource Planner**	Develops a >one year plan for the resource adequacy of specific loads within a Planning Coordinator area.
☒	**Transmission Planner**	Develops a >one year plan for the reliability of interconnected Bulk Power System within its portion of the Planning Coordinator area.
☐	**Transmission Service Provider**	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	**Transmission Owner**	Owns and maintains transmission facilities.
☒	**Transmission Operator**	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	**Distribution Provider**	Delivers electrical energy to the End-use customer.
☒	**Generator Owner**	Owns and maintains generation facilities.
☒	**Generator Operator**	Operates generation unit(s) to provide real and reactive power.
☐	**Purchasing-Selling Entity**	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	**Market Operator**	Interface point for reliability functions with commercial functions.
☒	**Load-Serving Entity**	Secures energy and transmission (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	**Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.**
☒	**The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.**
☒	**Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.**
☒	**Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.**
☒	**Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.**
☐	**Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.**
☐	**The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.**
Does the proposed Standard comply with all of the following Market Interface Principles? ***(Select 'yes' or 'no' from the drop-down box.)***	
The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes	
An Organization Standard shall not give any market participant an unfair competitive advantage.Yes	
An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes	
An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes	
An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Related Standards

Standard No.	Explanation
EOP-003-1	This standard may not be changed because of the work associated with Project 2007-01 but the standard drafting team should keep it in mind as they work on this set of standards.

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A: Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Mitigation Time Horizon
The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels
The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.

- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with 'Regional Entity'

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: PRC-006, PRC-007, and PRC-009 Standard Review Forms

Excerpted from NERC's Reliability Standards Development Plan: 2007 - 2009

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-006-0**	**Comments**
Title	Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs	Too long – slight difference with header.
Purpose		Implement vs. develop & document. Underfrequency spelled differently.
Applicability		RRO not in FM.
Requirements	*Conditions*	Okay
	Who?	R1.1 – includes sub-regions.
	Shall do what?	R1.3 – define sufficient; model at RRO or others or both? R1.4.2 – check grammar and capitalization; loosely worded. R2 & 3 – format of documentation.
	Result or Outcome	Missing
Measures		No real measures and definition of evidence required.
Issues to Consider	FERC NOPR o Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information. (see recommendations for improvement) FERC staff report o Concern with Blackout items (especially #21) o Fill in the blank o Definition of RRO as user of system o Lack of coordination Regional Fill-in-the-Blank Team Comments o Modify R1 to require each Region to develop a regional standard, and o Determine what elements (if any) of UFLS should be included in the North American standard and what elements should be included in the regional standards. o Development of regional standards needs to be coordinated with Regional entities. Regional entities should begin process for developing regional standards once the drafting team for the North American standard has determined what elements of UFLS should be included in the continent-wide standard and what elements should be included in the regional standards. o PRC-006 will be a continent-wide standard supported by Regional Reliability Standards. o Related PRC-007, PRC-008, and 009. V0 Industry Comments o Not a standalone standard o Who do you submit compliance material to? o Need to define evidence	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-007-0**	**Comments**
Title	Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organizations' Underfrequency Load Shedding Program Requirements	Too long and different than header.
Purpose		Same as 006 and doesn't address 007. No value proposition or benefit. Spelling of Underfrequency.
Applicability		Okay
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	R1 – what about coordination? R2 – provide format, etc. and define 'as necessary'.
	Result or Outcome	Missing
Measures		2 M for 3 R. M1 – define consistency M2 – define evidence
Issues to Consider	FERC NOPR o No changes identified. Regional Fill-in-the-Blank Team Comments o Change "program" to "standard" in R1. o Coordinated with PRC-006. o The regional procedures need to be converted to a standard to implement this. V0 Industry Comments o Need to include RA o Need to refine levels of non-compliance	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-009-0**	**Comments**
Title	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	Too long and different than header.
Purpose		Same as previous and it doesn't fit. No benefit or value proposition.
Applicability		Okay
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	Okay
	Result or Outcome	Missing
Measures		M1 not really a measure. M2 needs definition of evidence.
Issues to Consider	FERC NOPR o No changes identified. FERC staff report o No corresponding standard for under-voltage Regional Fill-in-the-Blank Team Comments o Change "program" to "standard'. o See notes for PRC-007. V0 Industry Comments o Define evidence o 90 days vs. 30 days o Exemptions for those with shunt reactors who don't shed load	

Appendix C: Issues Raised by Industry during 1st Posting of SAR for Project 2007-01

With respect to Question #2 of the comment form: *Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)*

NCMPA:

NCMPA1 agrees with the need to develop measures to shed load during an underfrequency event that are consistent across the interconnected electric system. However, NCMPA1 disagrees with the approach that has been taken by the regions in responding to this requirement, and we are concerned that the same approach is suggested in this SAR. We are specifically concerned that it is simply not practical for smaller entities to comply with the requirements proposed by this SAR.

As a result of the Energy Policy Act, many small utilities are required to register with their respective RROs, and these entities are now subject to mandatory compliance with the reliability standards. Some of these entities have peak annual loads that are smaller than 10 MW. Some are even smaller than 1 MW. Requirements within most, if not all, of the regions state that load must be shed in multiple steps (three steps in SERC, for example) at different underfrequency set points. While shedding load in multiple steps is perfectly rational for larger systems, most small loads are served by one distribution feeder bus. Furthermore, the entire peak demand on a small entity is a mere fraction of the amount of load that is shed by a larger entity in just one step. Furthermore, larger utilities have the advantage of aggregating load from multiple delivery points that can be shed in one step. Smaller entities do not have this advantage, and face the possibility of large expenditures in order to meet the multiple step shedding criteria.

NCMPA1 questions the benefit to reliability by requiring all utilities, regardless of size, to shed load in multiple steps as a result of an underfrequency event. We urge the SAR/standard drafting teams to address this issue and establish simplified requirements for small entities, whereby,

- Compliance with the UFLS standards be non-compulsory for entities with annual peak demands less than 10 MW
- Load shedding can be carried out in one step for entities with annual peak demands less than 100 MW.

American Electric Power

We would request that the drafting team consider geographic dispersion of the underfrequency response load.

We would request that this SAR apply to all entities that have an impact on the bulk energy system.

MRO

MRO believes that the UFLS standards, PRC-007 through PRC-009 could be broadly applied to ALL entities that comply with a customized Regional UFLS standard. Therefore, for simplification purposes, the MRO would support combining standards PRC-007 through PRC-009 into one UFLS NERC standard.

BPA Transmission Services

The To Do List for PRC-009 notes a consideration from V0 Industry Comments of an exemption for those with shunt reactors who don't shed load. As these devices are more associated with UVLS than UFLS, BPA reccommends the removal of this item.

PJM

There should only be 7 requirements in this standard. These seven would be split between NERC and the entity that has installed UFLS devices.

- NERC establish what the UFLS criteria should be, which would include transmission and generation UFLS set-points, time-delays, etc.
- NERC should establish acceptable maintenance intervals
- NERC shall establish and maintain a database of all UFLS information
- NERC should conduct an assessment of its criteria every five years
- Each entity shall meet the established criteria
- Each entity shall update its information in the NERC database each year
- Each entity shall investigate and analyze all UFLS events

The remaining requirements in the four standards should all go away. The entities would all be subject to compliance audits to verify their compliance

KCP&L

"Lack of coordination" - It is probably a good idea to know and understand the UFLS program requirements of neighboring regions.

"Develop Continent Standard" - The current standard is sufficient in scope and requirements to stand as a national standard. As stated above, the requirements are clear and complete to allow Regional Entities and their members to develop their unique UFLS programs, to implement them, to monitor the UFLS regional effectiveness and Regional member effectivness in maintaining their UFLS equipment. This standard serves a comprehensive national standard for developlement and implementation of UFLS in the regions.

"Who submit compliance material to?" - I think it is understood by the industry all compliance programs are administered by Reliability Coordinators and does not need to be included in this standard.

The remaining comments in this part of the SAR lack sufficient information to provide a specific response.

PRC-007

"Need language to implement" - I do not agree with the notion mentioned in the SAR document that it is necessary to add language requiring "implementation" of programs. The UFLS regional programs are required to specify in PRC-006 the frequency steps and load shed at a given step for TO's and Distribution Providers to adhere to. PRC-008 requires TO's and Distribution Providers to maintain and test their UFLS equipment. It is not possible to comply with these standards without equipment installed in the field.

PRC-008

"Maintenance intervals not addressed" - I do agree that a minimum maintenance interval should be included in the standard for the industry to comment on. I imagine solid state relays and electromechanical relays probably have differing maintenance needs.

PRC-009

"No correseponding standard for under-voltage" - This comment is outside the scope of this standard. Any development of an under-voltage standard should be separate and distinct from the UFLS standard. Both UFLS and under-voltage involve shedding of load but to address different operating condition recovery.

General comments:

The remainder of the SAR items in the "To Do Lists" are basically editorial in nature and do not change the substance of the standard. I do not have any fundamental problems with making the suggested modifications to the standards, but I also do not see any great need either. It is unclear who the entity responsible for determining the interconnections setpoints should be.

LADWP

Comments regarding the scope of the project (Question #2) and additional revisions that needs to be incorporated into the standards (Question #3).

The Reliability Functions checked off on page 3 of the SAR should include the Generator Owner and Generator Operator. This is because of the need to closely coordinate load tripping frequency settings to the generating unit off-nominal protection frequency and time delay settings. The objective is to provide enough separation between the load tripping and generating unit protection frequency and time delay settings. This will allow load tripping to be completed and thereby arrest system frequency decline without activating any generating unit off-nominal frequency protection.

The recommended generating unit off-nominal frequency protection settings vary depending on the unit manufacturer and type of unit. The number of generating units in an interconnection is numerous so will the variety of manufacturer's recommended off-nominal frequency and time delay settings. The worst case of these generating unit off-nominal protection settings have to be taken into account in determining the size of load tripped at each load-shedding step. If some units are not included in the consideration, it is possible for these units to have off-nominal settings that would trip the unit during load shedding, exacerbating the situation. A solution to this problem is requiring the owner of the generating unit to trip additional load to cover the additional loss of generation. But this solution is discriminatory if an extensive survey of generator off-nominal frequency protection was not conducted prior to the design of the load shedding steps. It would be similar to adding insult to injury to require generator owners to trip additional load when their generating units were excluded in the design of Regional Reliability Organization's (RRO) UFLS Program, in the first place. Besides these generator owners may not have load available for load shedding.

It is therefore important to add a requirement to "Standard PRC-006-0 – Development and Documentation of Regional UFLS programs that a thorough survey of all the off-nominal frequency protection settings of all interconnection generating units be conducted and the results used in the design of the RRO's Regional UFLS Program.

Manitoba Hydro

PRC-007 - To Do List:

- Need to include RA. [This should refer to the new functional model.]
- Need to refine levels of compliance. [In what manner? Different percentages of insufficient UFLS at stated non-compliance levels? Perhaps 90%-80%-70% instead of the 95%-90%-85% presently stated?]

PRC-008 - To Do List:

- Include a requirement that maintenance and testing of UFLS programs must be carried out with in a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System. [A maximum maintenance interval based on the relay type and system impact should not be defined by the standard. The required maintenance frequencies can not only be dependent upon relay type and system impact, but also many factors, including relay construction, age, maintenance practices, maintenance philosophies, environment, and operating context. The responsible entities are best situated to determine the maintenance requirements of their equipment. Revising PRC-008-0 requirements to be similar to the PRC-005-1 requirements provides more consistency across the standards and includes
  R1.1. Maintenance and testing intervals and their basis.
  R1.2. Summary of maintenance and testing intervals.

Both these requirements make available information which can be used for a review of an entity's maintenance frequencies and practices.]

PRC-009:

- Requirements – Result or Outcome. [Do not agree the “results” are “missing”. The results are inherently implied by adhering to the conditions stated in the requirements. Same as for PRC-007.]

Measures - [M1 - Disagree.]

To Do List:

- Change "program" to "standard" in R1. [Disagree. Using "standard" in this location of R1 could easily be confused with using the word "standard" in the rest of the document. There is nothing inappropriate with the word "program" in the context of R1. Same as for PRC-007.]
-90 days vs 30 days. [Depending on complexity of UFLS involved disturbance, 90 days may be required to properly analyze event and document results.]
-Exemptions for those with shunt reactor who don’t shed load. [Do not understand context of comment. Whether or not shunt reactors are tripped out by UF relays (possibly via UFLS relay facilities) is not relevant. Dumping reactors will increase voltages, but provide no significant (if any) improvements to sagging network frequency compare

So. Company Transmission, Generation, and Alabama Power

The term Evidence should be used in the Measurements in this standard as in other standards- it includes but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence.

With respect to Question #3 of the comment form: *Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.*

IRC Standards Review Committee

Please take a closer look at the applicability of each of the standard requirements. We believe some of them may not cover all the responsible entities. For example:

a. PRC-007-0
   TOP's & LSE's are missing from R1, R2 & M1.
b. PRC-008-0
   TOP's & LSE's are missing from the Applicability, Requirements & Measures sections.

MISO Stakeholders Committee

One major change needed in all the standards is to separate the standard into two pieces. The first is the set of core reliability requirements. The second portion is the supporting text. More than half the text in the current standards is supporting text that explains the true requirements. Now NERC is in the process of developing measures for and assigning risk to sentences that were never intended to be measured.

ATC

The SDT should also develop a new standard that addresses Generator Frequency Response. It’s our opinion that Generator Frequency Response goes hand-in-hand with Under Frequency Load Shedding and therefore should be included in this set of standards.

American Electric Power

We would request clarity regarding compliance measures. Some requirements will lend themselves to plus or minus tolerances for a prescribed value, while others may be best described in terms of greater than or less than the prescribed value.

Standard PRC-009 requires a simulation of the event (in addition to a description, a review of the set points and tripping times, and a summary of the findings). The time frame associated with providing documentation of the analysis, following the underfrequency event, is 90 calendar days (Requirement R2). Based on our experiences, we would request that the drafting team consider a longer time frame, such as 120 days.

ISO-NE

Because PRC-005, -008, -011, and -017 are related in the maintenance issues that they cover, there would be a benefit in consolidating these requirements of the standards into one standard.

PRC-006-0 would benefit from greater description as to the technical requirements. Specifically, R1.2.4 needs to be defined as to what particular generator protection schemes will be included in the requirement e.g. U/F trip settings.

R1.2.8 is too broad & encompassing in scope covering "any other schemes that are part of or impact the UFLS programs". The schemes that may be impacted by this requirement need to be defined in order to be measurable.

The levels of non-compliance should be augmented in PRC-006-0. For example, a level 2 non-compliance should be added for not meeting 2 or more elements of R1. A level 3 non-compliance should be added for not meeting R2. Level 4 non-compliance should be modified to target only those entities that do not complete a UFLS assessment within the last five years or those entities who do not provide this assessment to the regional entity.

As indicated by FERC, PRC-008 should be modified "to include a requirement that maintenance and testing of programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System."

The PRC Standards need to be reviewed to ensure applicable entities/functions are appropriately identified. TOP's & LSEs' are missing from: (i) R1, R2 & M1 in PRC-007, and (ii) the Applicability, Requirements and Measures sections in PRC-008. In addition, in certain instances (PRC-007 & -008), because independent system operators and regional transmission organizations are TOPs, the PRC-007 and PRC-008 may not be appropriately applied to these entities, because such entities do not own/operate UFLS.

The SAR should consider deleting PRC-009, and add the requirements to PRC-006-0 as R1.4.3.

KCP&L

The standards would be better organized by separating the reliability requirements from the supporting text that explains the requirements. Measures should then be applied only to the requirements and not the text.

Manitoba Hydro

PRC – 007:

- Purpose -If each standard included a list of all other closely related standards, the individual non-repeated purposes of related standards could be more easily compared by readers when necessary.
- Requirements – Shall Do What?
- R2 – "As necessary" should be removed. Annual updates of UFLS data to the RRO are necessary, even if they just only confirm that the previous year's data is still valid. Please refer to R3 comment below.

- R3 – Recommend further revision of R3. As well as RRO requested data within 30 days, there should be a mandatory requested annual update. This will coordinate with comment of R2.
- Measures - 2M for 3R.
- By making revisions to R2 and R3 as shown above, measure M2 will now appropriately cover both R2 and R3 for annual data updating and appropriate documentation transmission to RRO.

PRC-008-0:

Measure M1 needs to be revised to clearly reflect the measures applied to Requirement R1.

So. Company Transmission, Generation, and Alabama Power

Under PRC-006, Requirement 1.2, it is recommended the Regions have the responsibility for design details for determining Load Shedding Blocks (MWs), intentional and total tripping time delays, Generation protection, Islanding Schemes, Tie tripping schemes (within a Region), frequency set points (excludes BAL standard) and Load Restoration schemes. Also, the reporting of the time delay should only include the total time and not include the intentional time delay. The intentional time delay is included in the total time.

In PRC-006, Requirement 1.3, the Regional UFLS database is required to be updated at least every 5 years. However, under PRC-007, R2, the Transmission Owner is required to update its underfrequency data at least annually. These two timing update requirements should be consistent with one another.

In PRC-008 it is unclear how often the Transmission Owners are required to assess its maintenance and testing program. We recommend adding language to the SAR that says on a "as needed" basis.

Under PRC-008, Requirement 2, it states that Transmission Owner must implement its maintenance and testing program that is required in R1. It would seem more appropriate to include the implementation portion of R2 into R1 to say the Transmission Owner must have and implement a maintence and testing program.

The SAR drafting team should recognize that individual generator frequency trip set points are established by the manufacturer of the generator and not by the Generator Owner. Therefore, in the development of the underfrequency load shedding scheme, each Transmission Owner should recognize that these generator frequency trip settings cannot be adjusted and the load shedding schemes should take this into account. This standard should not require a Generator Owner to operate beyond the limits set by the manufacturer.

Standard Authorization Request Form

Title of Proposed Standard **Project 2007-01**	**Underfrequency Load Shedding (UFLS) Standards**
Request Date **Revised**	**November 14, 2006** **March 28, 2007**

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Regional Reliability Standards Working Group	☐ ☐	New Standard
Primary Contact **Robert W. Millard** **Director of Standards** **ReliabilityFirst Corporation**	☒	Revision to existing Standards PRC-006, PRC-007, ~~PRC-008,~~ and PRC-009
Telephone (630) 261-2621 **Fax (630) 691-4222**	☐ ☐	Withdrawal of existing Standard
E-mailbob.millard@rfirst.org	☐ ☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

PRC-006— Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
PRC-007 — Assuring Consistency with Regional UFLS Programs
~~PRC-008 — Underfrequency Load Shedding Equipment Maintenance Programs~~
PRC-009 — UFLS Performance Following an Underfrequency Event

The purpose of revising the above ~~four~~ standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems ~~–~~ – ensure each of the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties - the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Incorporate other general improvements described in ~~the~~NERC's Reliability Standards Development Plan: 2007-2009 (summarized and outlined in the Reliability Standard Review Guidelines attached as Appendix A).
4. Consider the items mentioned in the Standard Review Forms (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) attached as Appendix B, prepared by the NERC staff, which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006) ,
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,
    - Version 0 standards development ~~work plan.~~(see note 1), and

~~4.Consider comments received during the initial development of the standards and other comments received from ERO regulatory authorities and stakeholders, as noted in the attached review sheets.~~

    - Regional Fill-in-the-Blank Team (RRSWG – a NERC working group involved with regional standards development).

    The standard drafting team should also consider any other issues that were not completely captured but were stated or referenced in the above materials.

5. Consider issues raised by the industry during the posting of the SAR for Project 2007-01 during the first comment period from November 29, 2006 through January 12, 2007, attached as Appendix C.
6. Satisfy the standards procedure requirement for five-year review of the standards.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

The ~~four~~ standards in this set are all Version 0 standards. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to stand up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

PRC-006 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The standard drafting team (SDT) will work with stakeholders to review PRC-006 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to and contained with the UFLS ~~procedures to~~ program documentation. The SDT shall determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

PRC-007 ~~through~~and PRC-009 have some 'fill-in-the-blank' characteristics, as identified in the Regional Reliability Standards Working Group work plan, which need to be removed. These standards shall be included with PRC-006 for consideration as one or more revised standards as necessary for consistency and clarity of overall program requirements and any other associated programs and/or requirements that affect or impact the UFLS program.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	**Reliability ~~Authority~~Coordinator**	~~Ensures~~Responsible for the real-time operating reliability of ~~the bulk transmission system within~~ its Reliability ~~Authority area. This is the highest~~Coordinator Area in coordination with its neighboring Reliability ~~Authority.~~Coordinator's wide area view.
☒	**Balancing Authority**	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.

☐	**Interchange ~~Authority~~Coordinator**	~~Authorizes~~Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced ~~Interchange Schedules.~~interchange schedules between Balancing Authority Areas.
☒	**Planning ~~Authority~~Coordinator**	~~Plans the Bulk Electric System.~~ Assesses the longer-term reliability of its Planning Coordinator Area.
☐	**Resource Planner**	Develops a ~~long-term (~~>one year~~)~~ plan for the resource adequacy of specific loads within a Planning ~~Authority~~Coordinator area.
☒	**Transmission Planner**	Develops a ~~long-term (~~>one year~~)~~ plan for the reliability of ~~transmission systems~~interconnected Bulk Power System within its portion of the Planning ~~Authority~~Coordinator area.
☐	**Transmission Service Provider**	~~Provides~~Administers the transmission tariff and provides transmission services ~~to qualified market participants~~ under applicable transmission service agreements (e.g., the pro forma tariff).
☒	**Transmission Owner**	Owns and maintains transmission facilities.
☒	**Transmission Operator**	~~Operates and maintains the transmission facilities, and executes switching orders.~~Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	**Distribution Provider**	~~Provides and operates the "wires" between the transmission system and the customer.~~Delivers electrical energy to the End-use customer.
☒	**Generator Owner**	Owns and maintains generation ~~unit(s).~~facilities.
☒	**Generator Operator**	Operates generation unit(s) to provide real and ~~performs the functions of supplying energy and Interconnected Operations Services.~~reactive power.
☐	**Purchasing-Selling Entity**	~~The function of purchasing~~Purchases or ~~selling~~sells energy, capacity, and ~~all~~ necessary ~~Interconnected Operations Services~~reliability-related services as required.
☐	**Market Operator**	~~Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.~~Interface point for reliability functions with commercial functions.
☒	**Load-Serving Entity**	Secures energy and transmission (and related ~~generation~~reliability-related services) to serve the ~~end user~~End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	**~~1.~~ Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.**
☒	**~~2.~~ The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.**
☒	**~~3.~~ Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.**
☒	**~~4.~~ Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.**
☒	**~~5.~~ Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.**
☐	**~~6.~~ Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.**
☐	**~~7.~~ The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.**
Does the proposed Standard comply with all of the following Market Interface Principles? ***(Select 'yes' or 'no' from the drop-down box.)***	
~~1.~~ The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes	
~~2.~~ An Organization Standard shall not give any market participant an unfair competitive advantage.Yes	
~~3.~~ An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes	
~~4.~~ An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes	
~~5.~~ An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Related Standards

Standard No.	Explanation
EOP-003-1	This standard may not be changed because of the work associated with Project 2007-01 but the standard drafting team should keep it in mind as they work on this set of standards.

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A: Reliability Standard Review Guidelines

Applicability

Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose

Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements

Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability

Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations

Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness

Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Mitigation Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.

- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with 'Regional Entity'

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: PRC-006, PRC-007, and PRC-009 Standard Review Forms

Excerpted from NERC's Reliability Standards Development Plan: 2007 - 2009

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-006-0**	**Comments**
Title	Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs	Too long – slight difference with header.
Purpose		Implement vs. develop & document. Underfrequency spelled differently.
Applicability		RRO not in FM.
Requirements	*Conditions*	Okay
	Who?	R1.1 – includes sub-regions.
	Shall do what?	R1.3 – define sufficient; model at RRO or others or both? R1.4.2 – check grammar and capitalization; loosely worded. R2 & 3 – format of documentation.
	Result or Outcome	Missing
Measures		No real measures and definition of evidence required.
~~**To Do List**~~**Issues to Consider**	FERC NOPR o Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information. (see recommendations for improvement) FERC staff report o Concern with Blackout items (especially #21) o Fill in the blank o Definition of RRO as user of system o Lack of coordination Regional Fill-in-the-Blank Team Comments o Modify R1 to require each Region to develop a regional standard, and o Determine what elements (if any) of UFLS should be included in the North American standard and what elements should be included in the regional standards. o Development of regional standards needs to be coordinated with Regional entities. Regional entities should begin process for developing regional standards once the drafting team for the North American standard has determined what elements of UFLS should be included in the continent-wide standard and what elements should be included in the regional standards. o PRC-006 will be a continent-wide standard supported by Regional Reliability Standards. o Related PRC-007, PRC-008, and 009. V0 Industry Comments o Not a standalone standard o Who do you submit compliance material to? o Need to define evidence	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-007-0**	**Comments**
Title	Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organizations' Underfrequency Load Shedding Program Requirements	Too long and different than header.
Purpose		Same as 006 and doesn't address 007. No value proposition or benefit. Spelling of Underfrequency.
Applicability		Okay
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	R1 – what about coordination? R2 – provide format, etc. and define 'as necessary'.
	Result or Outcome	Missing
Measures		2 M for 3 R. M1 – define consistency M2 – define evidence
~~**To Do List**~~**Issues to Consider**	FERC NOPR o No changes identified. Regional Fill-in-the-Blank Team Comments o Change "program" to "standard" in R1. o Coordinated with PRC-006. o The regional procedures need to be converted to a standard to implement this. V0 Industry Comments o Need to include RA o Need to refine levels of non-compliance	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-008-0**	**Comments**
Title	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	Too long and different than header. Doesn't cover testing element.
Purpose		Same statement that has been carried forward and doesn't fit here. No benefit or value proposition.
Applicability		Okay
Requirements	*Conditions*	Not clear how this differs from 005.
	Who?	Okay
	Shall do what?	R2 – format, etc. missing.
	Result or Outcome	Missing
Measures		M2 needs to define evidence.
To Do List	FERC NOPR oInclude a requirement that maintenance and testing of UFLS programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk Power System. FERC staff report oMaintenance intervals not addressed Regional Fill-in-the-Blank Team Comments oOkay if PRC-006 is fixed V0 Industry Comments oConsistent wording from standard to standard required oDefinition of evidence required	

Standard Review Form Project 2007-01 Underfrequency Load Shedding		
Standard #	**PRC-009-0**	**Comments**
Title	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	Too long and different than header.
Purpose		Same as previous and it doesn't fit. No benefit or value proposition.
Applicability		Okay
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	Okay
	Result or Outcome	Missing
Measures		M1 not really a measure. M2 needs definition of evidence.
~~To Do List~~Issues to Consider	FERC NOPR o No changes identified. FERC staff report o No corresponding standard for under-voltage Regional Fill-in-the-Blank Team Comments o Change "program" to "standard'. o See notes for PRC-007. V0 Industry Comments o Define evidence o 90 days vs. 30 days o Exemptions for those with shunt reactors who don't shed load	

Appendix C: Issues Raised by Industry during 1st Posting of SAR for Project 2007-01

With respect to Question #2 of the comment form: *Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)*

NCMPA:

NCMPA1 agrees with the need to develop measures to shed load during an underfrequency event that are consistent across the interconnected electric system. However, NCMPA1 disagrees with the approach that has been taken by the regions in responding to this requirement, and we are concerned that the same approach is suggested in this SAR. We are specifically concerned that it is simply not practical for smaller entities to comply with the requirements proposed by this SAR.

As a result of the Energy Policy Act, many small utilities are required to register with their respective RROs, and these entities are now subject to mandatory compliance with the reliability standards. Some of these entities have peak annual loads that are smaller than 10 MW. Some are even smaller than 1 MW. Requirements within most, if not all, of the regions state that load must be shed in multiple steps (three steps in SERC, for example) at different underfrequency set points. While shedding load in multiple steps is perfectly rational for larger systems, most small loads are served by one distribution feeder bus. Furthermore, the entire peak demand on a small entity is a mere fraction of the amount of load that is shed by a larger entity in just one step. Furthermore, larger utilities have the advantage of aggregating load from multiple delivery points that can be shed in one step. Smaller entities do not have this advantage, and face the possibility of large expenditures in order to meet the multiple step shedding criteria.

NCMPA1 questions the benefit to reliability by requiring all utilities, regardless of size, to shed load in multiple steps as a result of an underfrequency event. We urge the SAR/standard drafting teams to address this issue and establish simplified requirements for small entities, whereby,

- Compliance with the UFLS standards be non-compulsory for entities with annual peak demands less than 10 MW
- Load shedding can be carried out in one step for entities with annual peak demands less than 100 MW.

American Electric Power

We would request that the drafting team consider geographic dispersion of the underfrequency response load.

We would request that this SAR apply to all entities that have an impact on the bulk energy system.

MRO

MRO believes that the UFLS standards, PRC-007 through PRC-009 could be broadly applied to ALL entities that comply with a customized Regional UFLS standard. Therefore, for simplification purposes, the MRO would support combining standards PRC-007 through PRC-009 into one UFLS NERC standard.

BPA Transmission Services

The To Do List for PRC-009 notes a consideration from V0 Industry Comments of an exemption for those with shunt reactors who don't shed load. As these devices are more associated with UVLS than UFLS, BPA reccommends the removal of this item.

PJM

There should only be 7 requirements in this standard. These seven would be split between NERC and the entity that has installed UFLS devices.

- NERC establish what the UFLS criteria should be, which would include transmission and generation UFLS set-points, time-delays, etc.
- NERC should establish acceptable maintenance intervals
- NERC shall establish and maintain a database of all UFLS information
- NERC should conduct an assessment of its criteria every five years
- Each entity shall meet the established criteria
- Each entity shall update its information in the NERC database each year
- Each entity shall investigate and analyze all UFLS events

The remaining requirements in the four standards should all go away. The entities would all be subject to compliance audits to verify their compliance

KCP&L

"Lack of coordination" - It is probably a good idea to know and understand the UFLS program requirements of neighboring regions.

"Develop Continent Standard" - The current standard is sufficient in scope and requirements to stand as a national standard. As stated above, the requirements are clear and complete to allow Regional Entities and their members to develop their unique UFLS programs, to implement them, to monitor the UFLS regional effectiveness and Regional member effectivness in maintaining their UFLS equipment. This standard serves a comprehensive national standard for developlement and implementation of UFLS in the regions.

"Who submit compliance material to?" - I think it is understood by the industry all compliance programs are administered by Reliability Coordinators and does not need to be included in this standard.

The remaining comments in this part of the SAR lack sufficient information to provide a specific response.

PRC-007

"Need language to implement" - I do not agree with the notion mentioned in the SAR document that it is necessary to add language requiring "implementation" of programs. The UFLS regional programs are required to specify in PRC-006 the frequency steps and load shed at a given step for TO's and Distribution Providers to adhere to. PRC-008 requires TO's and Distribution Providers to maintain and test their UFLS equipment. It is not possible to comply with these standards without equipment installed in the field.

PRC-008

"Maintenance intervals not addressed" - I do agree that a minimum maintenance interval should be included in the standard for the industry to comment on. I imagine solid state relays and electromechanical relays probably have differing maintenance needs.

PRC-009

"No corresponding standard for under-voltage" - This comment is outside the scope of this standard. Any development of an under-voltage standard should be separate and distinct from the UFLS standard. Both UFLS and under-voltage involve shedding of load but to address different operating condition recovery.

General comments:

The remainder of the SAR items in the "To Do Lists" are basically editorial in nature and do not change the substance of the standard. I do not have any fundamental problems with making the suggested modifications to the standards, but I also do not see any great need either. It is unclear who the entity responsible for determining the interconnections setpoints should be.

LADWP

Comments regarding the scope of the project (Question #2) and additional revisions that needs to be incorporated into the standards (Question #3).

The Reliability Functions checked off on page 3 of the SAR should include the Generator Owner and Generator Operator. This is because of the need to closely coordinate load tripping frequency settings to the generating unit off-nominal protection frequency and time delay settings. The objective is to provide enough separation between the load tripping and generating unit protection frequency and time delay settings. This will allow load tripping to be completed and thereby arrest system frequency decline without activating any generating unit off-nominal frequency protection.

The recommended generating unit off-nominal frequency protection settings vary depending on the unit manufacturer and type of unit. The number of generating units in an interconnection is numerous so will the variety of manufacturer's recommended off-nominal frequency and time delay settings. The worst case of these generating unit off-nominal protection settings have to be taken into account in determining the size of load tripped at each load-shedding step. If some units are not included in the consideration, it is possible for these units to have off-nominal settings that would trip the unit during load shedding, exacerbating the situation. A solution to this problem is requiring the owner of the generating unit to trip additional load to cover the additional loss of generation. But this solution is discriminatory if an extensive survey of generator off-nominal frequency protection was not conducted prior to the design of the load shedding steps. It would be similar to adding insult to injury to require generator owners to trip additional load when their generating units were excluded in the design of Regional Reliability Organization's (RRO) UFLS Program, in the first place. Besides these generator owners may not have load available for load shedding.

It is therefore important to add a requirement to "Standard PRC-006-0 – Development and Documentation of Regional UFLS programs that a thorough survey of all the off-nominal frequency protection settings of all interconnection generating units be conducted and the results used in the design of the RRO's Regional UFLS Program.

Manitoba Hydro

PRC-007 - To Do List:

- Need to include RA. [This should refer to the new functional model.]
- Need to refine levels of compliance. [In what manner? Different percentages of insufficient UFLS at stated non-compliance levels? Perhaps 90%-80%-70% instead of the 95%-90%-85% presently stated?]

PRC-008 - To Do List:

- Include a requirement that maintenance and testing of UFLS programs must be carried out with in a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System. [A maximum maintenance interval based on the relay type and system impact should not be defined by the standard. The required maintenance frequencies can not only be dependent upon relay type and system impact, but also many factors, including relay construction, age, maintenance practices, maintenance philosophies, environment, and operating context. The responsible entities are best situated to determine the maintenance requirements of their equipment. Revising PRC-008-0 requirements to be similar to the PRC-005-1 requirements provides more consistency across the standards and includes
  R1.1. Maintenance and testing intervals and their basis.
  R1.2. Summary of maintenance and testing intervals.

Both these requirements make available information which can be used for a review of an entity's maintenance frequencies and practices.]

PRC-009:

- Requirements – Result or Outcome. [Do not agree the "results" are "missing". The results are inherently implied by adhering to the conditions stated in the requirements. Same as for PRC-007.]

Measures - [M1 - Disagree.]

To Do List:

- Change "program" to "standard" in R1. [Disagree. Using "standard" in this location of R1 could easily be confused with using the word "standard" in the rest of the document. There is nothing inappropriate with the word "program" in the context of R1. Same as for PRC-007.]
-90 days vs 30 days. [Depending on complexity of UFLS involved disturbance, 90 days may be required to properly analyze event and document results.]
-Exemptions for those with shunt reactor who don't shed load. [Do not understand context of comment. Whether or not shunt reactors are tripped out by UF relays (possibly via UFLS relay facilities) is not relevant. Dumping reactors will increase voltages, but provide no significant (if any) improvements to sagging network frequency compare

So. Company Transmission, Generation, and Alabama Power

The term Evidence should be used in the Measurements in this standard as in other standards- it includes but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence.

With respect to Question #3 of the comment form: *Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.*

IRC Standards Review Committee

Please take a closer look at the applicability of each of the standard requirements. We believe some of them may not cover all the responsible entities. For example:

a. PRC-007-0

TOP's & LSE's are missing from R1, R2 & M1.

b. PRC-008-0

TOP's & LSE's are missing from the Applicability, Requirements & Measures sections.

MISO Stakeholders Committee

One major change needed in all the standards is to separate the standard into two pieces. The first is the set of core reliability requirements. The second portion is the supporting text. More than half the text in the current standards is supporting text that explains the true requirements. Now NERC is in the process of developing measures for and assigning risk to sentences that were never intended to be measured.

ATC

The SDT should also develop a new standard that addresses Generator Frequency Response. It's our opinion that Generator Frequency Response goes hand-in-hand with Under Frequency Load Shedding and therefore should be included in this set of standards.

American Electric Power

We would request clarity regarding compliance measures. Some requirements will lend themselves to plus or minus tolerances for a prescribed value, while others may be best described in terms of greater than or less than the prescribed value.

Standard PRC-009 requires a simulation of the event (in addition to a description, a review of the set points and tripping times, and a summary of the findings). The time frame associated with providing documentation of the analysis, following the underfrequency event, is 90 calendar days (Requirement R2). Based on our experiences, we would request that the drafting team consider a longer time frame, such as 120 days.

ISO-NE

Because PRC-005, -008, -011, and -017 are related in the maintenance issues that they cover, there would be a benefit in consolidating these requirements of the standards into one standard.

PRC-006-0 would benefit from greater description as to the technical requirements. Specifically, R1.2.4 needs to be defined as to what particular generator protection schemes will be included in the requirement e.g. U/F trip settings.

R1.2.8 is too broad & encompassing in scope covering "any other schemes that are part of or impact the UFLS programs". The schemes that may be impacted by this requirement need to be defined in order to be measurable.

The levels of non-compliance should be augmented in PRC-006-0. For example, a level 2 non-compliance should be added for not meeting 2 or more elements of R1. A level 3 non-compliance should be added for not meeting R2. Level 4 non-compliance should be modified to target only those entities that do not complete a UFLS assessment within the last five years or those entities who do not provide this assessment to the regional entity.

As indicated by FERC, PRC-008 should be modified "to include a requirement that maintenance and testing of programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System."

The PRC Standards need to be reviewed to ensure applicable entities/functions are appropriately identified. TOP's & LSEs' are missing from: (i) R1, R2 & M1 in PRC-007, and (ii) the Applicability, Requirements and Measures sections in PRC-008. In addition, in certain instances (PRC-007 & -008), because independent system operators and regional transmission organizations are TOPs, the PRC-007 and PRC-008 may not be appropriately applied to these entities, because such entities do not own/operate UFLS.

The SAR should consider deleting PRC-009, and add the requirements to PRC-006-0 as R1.4.3.

KCP&L

The standards would be better organized by separating the reliability requirements from the supporting text that explains the requirements. Measures should then be applied only to the requirements and not the text.

Manitoba Hydro

PRC – 007:

- Purpose -If each standard included a list of all other closely related standards, the individual non-repeated purposes of related standards could be more easily compared by readers when necessary.
- Requirements – Shall Do What?
- R2 – "As necessary" should be removed. Annual updates of UFLS data to the RRO are necessary, even if they just only confirm that the previous year's data is still valid. Please refer to R3 comment below.

- R3 – Recommend further revision of R3. As well as RRO requested data within 30 days, there should be a mandatory requested annual update. This will coordinate with comment of R2.
- Measures - 2M for 3R.
- By making revisions to R2 and R3 as shown above, measure M2 will now appropriately cover both R2 and R3 for annual data updating and appropriate documentation transmission to RRO.

PRC-008-0:

Measure M1 needs to be revised to clearly reflect the measures applied to Requirement R1.

So. Company Transmission, Generation, and Alabama Power

Under PRC-006, Requirement 1.2, it is recommended the Regions have the responsibility for design details for determining Load Shedding Blocks (MWs), intentional and total tripping time delays, Generation protection, Islanding Schemes, Tie tripping schemes (within a Region), frequency set points (excludes BAL standard) and Load Restoration schemes. Also, the reporting of the time delay should only include the total time and not include the intentional time delay. The intentional time delay is included in the total time.

In PRC-006, Requirement 1.3, the Regional UFLS database is required to be updated at least every 5 years. However, under PRC-007, R2, the Transmission Owner is required to update its underfrequency data at least annually. These two timing update requirements should be consistent with one another.

In PRC-008 it is unclear how often the Transmission Owners are required to assess its maintenance and testing program. We recommend adding language to the SAR that says on a "as needed" basis.

Under PRC-008, Requirement 2, it states that Transmission Owner must implement its maintenance and testing program that is required in R1. It would seem more appropriate to include the implementation portion of R2 into R1 to say the Transmission Owner must have and implement a maintence and testing program.

The SAR drafting team should recognize that individual generator frequency trip set points are established by the manufacturer of the generator and not by the Generator Owner. Therefore, in the development of the underfrequency load shedding scheme, each Transmission Owner should recognize that these generator frequency trip settings cannot be adjusted and the load shedding schemes should take this into account. This standard should not require a Generator Owner to operate beyond the limits set by the manufacturer.

Nomination Form — Underfrequency Load Shedding Standard Drafting Team

Please return this form to sarcomm@nerc.com by **March 29, 2007**. For questions, please contact Gerry Adamski at 609-452-8060 or gerry.adamski@nerc.net

Name: Organization: Address: Office Telephone: E-mail:
Please briefly describe your experience and qualifications to serve on the Underfrequency Load Shedding Standard Drafting Team. Prefer experience in developing load shedding plans, in specifying criteria for load shedding plans, in testing load shedding plans, or in analyzing load shedding events. Previous experience working on or applying NERC or IEEE standards is beneficial, but not a requirement.

I represent the following NERC Reliability Region(s) (check all that apply):	**I represent the following Industry Segment (check one):**	
☐ ERCOT	☐	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs, ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations and Regional Entities

Check the responsible entities[1] in which you have expertise or responsibilities:	
☐ Reliability Coordinator	☐ Transmission Service Provider
☐ Balancing Authority	☐ Transmission Owner
☐ Interchange Authority	☐ Load Serving Entity
☐ Planning Coordinator	☐ Distribution Provider
☐ Transmission Operator	☐ Purchasing-Selling Entity
☐ Generator Operator	☐ Generator Owner
☐ Transmission Planner	☐ Resource Planner
	☐ Market Operator

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.	
Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

[1] These responsible entities are defined in the Functional Model, Version 3 which is downloadable from the following Web site: http://www.nerc.com/~filez/functionalmodel.html

Maureen E. Long
Standards Process Manager

March 15, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement
Nominations Periods Open for Two Drafting Teams

The Standards Committee (SC) announces the following standards actions:

Nominations for Project 2007-01 Underfrequency Load Shedding Standard Drafting Team (March 15–29, 2007)

The Standards Committee is seeking industry experts to serve on the Underfrequency Load Shedding Standard Drafting Team. The SAR calls for the modification of the following standards:

> PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
>
> PRC-007 — Assuring Consistency with Regional UFLS Programs
>
> PRC-009 — UFLS Performance Following an Underfrequency Event

This project involves upgrading the overall quality of these four standards; eliminating some gaps in the requirements; eliminating some ambiguity; and eliminating some "fill-in-the-blank" components.

If you are interested in serving on this team, please complete this nomination form and return it to Gerry Adamski (Gerry.Adamski@nerc.net) no later than March 29, 2007.

Nominations for Project 2007-02 Operating Personnel Communications Protocols SAR Drafting Team (March 15–29, 2007)

The Standards Committee is seeking industry experts to serve on the Operating Personnel Communications Protocols SAR Drafting Team. This SAR calls for the development of communications protocols for use by real-time system operators to improve situational awareness and shorten response time.

If you are interested in serving on this team, please complete this nomination form and return it to Gerry Adamski (Gerry.Adamski@nerc.net) no later than March 29, 2007.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for Underfrequency Load Shedding Regional Reliability Standard Characteristics

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before these Underfrequency Load Shedding (UFLS) Regional Reliability Standard characteristics and associated regional reliability standards can be implemented.

Compliance with Standards

Once a UFLS regional reliability standard becomes effective, the responsible entities identified in the applicability section of the specific standard must comply with the requirements.

Proposed Effective Date

Compliance with the individual UFLS regional reliability standards shall be effective according to the approved effective date of the specific regional reliability standard.

Retired Standards

PRC-006-0 — Development and Documentation of Regional UFLS Programs will be completely retired once all eight UFLS regional reliability standards become effective. PRC-006-0 will remain in effect for any region without an effective UFLS regional reliability standard.

PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements will be completely retired once all eight UFLS regional reliability standards become effective. PRC-007-0 will remain in effect for any region without an effective UFLS regional reliability standard.

PRC-009-0 — UFLS Performance Following an Underfrequency Event will be completely retired once all eight UFLS regional reliability standards become effective. PRC-009-0 will remain in effect for any region without an effective UFLS regional reliability standard.

The following tables provide a mapping of the existing requirements to be retired relative to the resolution of the requirement going forward with the implementation of regional standards in accordance with the Underfrequency Load Shedding Regional Reliability Standard Characteristics.

Standard	Requirement	Location	Needed for Reliability
PRC-006-0	**R1:** Each Regional Reliability Organization shall develop, coordinate, and document an UFLS program, which shall include the following:	UFLS Regional Reliability Standard Characteristics 1, 2, and 3.	Yes
	R1.1: Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations.	UFLS Regional Reliability Standard Characteristic 3.	Yes
	R1.2: Design details shall include, but are not limited to: **R.1.2.1**: Frequency set points. **R.1.2.2**: Size of corresponding load shedding blocks (% of connected loads.) **R.1.2.3**: Intentional and total tripping time delays. **R.1.2.4**: Generation protection. **R.1.2.5**: Tie tripping schemes. **R.1.2.6**: Islanding schemes. **R.1.2.7**: Automatic load restoration schemes. **R.1.2.8**: Any other schemes that are part of or impact the UFLS programs.	These design details will be included in the Regional Standards, and will be established within each region to meet the common system performance standard defined by UFLS Regional Reliability Standard Characteristics 4 and 5.	Yes
	R1.3: A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.	UFLS Regional Reliability Standard Characteristics 7 and 8.	Yes

Standard	Requirement	Location	Needed for Reliability
	R1.4: Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to: **R1.4.1**: A review of the frequency set points and timing, and **R1.4.2**: Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation.	UFLS Regional Reliability Standard Characteristic 10.	Yes
	R2: The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).	UFLS Regional Reliability Standard Characteristics 7 and 8.	Yes
	R3: The Regional Reliability Organization shall provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days).	UFLS Regional Reliability Standard Characteristic 10.	Yes

Standard	Requirement	Location	Needed for Reliability
PRC-007-0	**R1**: The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.	UFLS Regional Reliability Standard Characteristic 11.	Yes
	R2: The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.	UFLS Regional Reliability Standard Characteristics 7 and 8.	Yes
	R3: The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).	UFLS Regional Reliability Standard Characteristic 10.	Yes

Standard	Requirement	Location	Needed for Reliability
PRC-009-0	**R1.** The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:,:	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	Yes
	R1.1. A description of the event including initiating conditions.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	Yes
	R1.2. A review of the UFLS set points and tripping times.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296:	Yes

Standard	Requirement	Location	Needed for Reliability
		A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	
	R1.3. A simulation of the event.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	Yes
	R1.4. A summary of the findings.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events	Yes

Standard	Requirement	Location	Needed for Reliability
		leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	
	R2. The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	Yes

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Comment Form for 1st Draft of Under Frequency Load Shedding Regional Reliability Standard Characteristics — Project 2007-01

Please **DO NOT** use this form to submit comments on the proposed 1st draft of the Under Frequency Load Shedding Regional Reliability Standard Characteristics developed by the standard drafting team for Project 2007-01 – Underfrequency Load Shedding. Comments must be submitted by **August 15, 2008**. If you have questions please contact Stephanie Monzon at stephanie.monzon@nerc.net or by telephone at 610-608-8084.

Please submit your comments by using the Electronic Comment Form posted on the Project 2007-01 Underfrequency Load Shedding Drafting Team Web site.

Background Information

The major objectives of Project 2007-01 Underfrequency Load Shedding are to:

1) Ensure UFLS standards are developed that are complete and the requirements are set at an appropriate level to ensure reliability (not least common denominator).
2) Ensure that the standards are enforceable with clearly defined requirements and unambiguous language.
3) Address the issues raised by FERC Order 693 and other applicable orders.
4) Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5) Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

The standard drafting team (SDT) for Project 2007-01 Underfrequency Load Shedding (UFLS) based its work on the existing NERC standards:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs,
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements, and
- PRC-009-0 — UFLS Performance Following an Underfrequency Event.

Project 2007-01 Under Frequency Load Shedding is one of four projects[1] identified in the Reliability Standards Development Plan 2008-2010 as requiring a set of Regional Standards to support a continent-wide standard.

In accordance with the associated SAR, a standard drafting team was appointed to draft the continent-wide UFLS standard with consideration of developing supporting regional standards. The team is recommending that, instead of developing a continent-wide standard, NERC issue a set of UFLS performance characteristics required in regional reliability standards for implementing automatic UFLS programs to arrest declining Bulk Electric System frequency.

NERC will include the approved UFLS Regional Reliability Standard Characteristics in a directive that it provides to each regional entity requiring the regional entity to develop a regional UFLS reliability standard. NERC is authorized to direct a regional entity to develop a

[1] The other three projects were, Project 2007-05 Balancing Authority Controls; Project 2007-11 Disturbance Monitoring; and Project 2008-04 Protection Systems

regional standard pursuant to section 312.2 of the Rules of Procedure of the North American Electric Reliability Corporation which states:

> **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform reliability standards across North America, in some cases it may not be feasible to achieve a reliability objective with a reliability standard that is uniformly applicable across North America. In such cases, NERC may direct regional entities to develop regional reliability standards necessary to implement a NERC reliability standard. Such regional reliability standards that are developed pursuant to a direction by NERC shall be made part of the NERC reliability standards.

The standard drafting team's proposed approach of establishing common system performance characteristics rather than prescribing a uniform design specification for all UFLS programs within a continent-wide standard recognizes that the objective of the UFLS programs is to arrest and recover frequency in islanded portions of an interconnection. In addition, UFLS programs with differing design specifications can be successfully coordinated if they are designed to achieve the same system performance characteristics, even across interconnected regions.

The drafting team reviewed the existing UFLS programs from each Region and it became clear that various combinations of load steps and frequency set points exist and can achieve the objective of arresting and recovering frequency. Also, it became clear that there is not one way to design a UFLS program. Additional reasons the drafting team is recommending the development of a UFLS Regional Standard as opposed to a continent-wide standard:

- The Region's UFLS programs are repeatedly evaluated for their effectiveness;
- Applicability and responsibility for a UFLS program varies among the Regions;
- A UFLS infrastructure is already in place within each Region and to convert to one UFLS program would take time/effort and expense; and
- The expertise resides in each region to develop a UFLS Regional Standard.

Part of the intent of directing the regions to develop UFLS Regional Standards is because each regional entity has specific expertise relative to defining credible islands within or between its region and neighboring regions. The regional entities also have specific expertise for assessing islands within their regions based on electrically interconnected areas. Analysis of islands occurring between regions is intended to require coordination of programs by the Regions across which an island may form.

Characteristics of UFLS Regional Reliability Standards

The SDT developed the set of characteristics which each of the regional entities will be directed to include in its UFLS regional reliability standard. The SDT developed these characteristics for directing the regional entities in developing requirements that can be defined based on system performance, without prescribing specifics of how these system performance requirements should be met. This approach for identifying regional reliability standard characteristics for implementation of a regional standard by a regional entity is being used for the very first time by a NERC drafting team.

The technical basis for each of the parameters is summarized as:

- Frequency decline shall be arrested at no less than 58.0 Hz.

  The technical basis for this design parameter is coordination with generating unit protections and the generator underfrequency tripping requirements proposed by the

Generator Verification Standard Drafting Team. The tripping threshold proposed for NERC Reliability Standard PRC-024 is 57.8 Hz with no intentional time delay. Arresting declining frequency within an island at or above 58.0 Hz provides proper coordination to prevent tripping of generation prior to allowing the UFLS program to arrest frequency decline.

- Frequency shall not remain below 58.5 Hz for greater than 10 seconds, cumulatively, and shall not remain below 59.5 Hz for greater than 30 seconds, cumulatively.

  The technical basis for this design parameter is coordination with generating unit protection and the generator underfrequency tripping requirements proposed by the Generator Verification Standard Drafting Team. Recovering frequency within an island in accordance with these parameters avoids operating conditions for which the generating units are subject to turbine damage and provides proper coordination to prevent tripping of generation prior to allowing the UFLS program to recover frequency.

- Frequency overshoot resulting from operation of UFLS relays shall not exceed 61.0 Hz for any duration and shall not exceed 60.5 Hz for greater than 30 seconds, cumulatively.

  The technical basis for this design parameter is coordination with generating unit protection and the generator overfrequency tripping requirements proposed by the Generator Verification Standard Drafting Team. Controlling frequency overshoot during frequency recovery within an island in accordance with these parameters avoids operating conditions for which the generating units are subject to turbine damage and provides proper coordination to prevent tripping of generation, which could lead to additional UFLS operations and possible frequency collapse.

- Bulk Electric System voltage during and following UFLS operations shall be controlled such that the per unit Volts per Hz (V/Hz) will not exceed 1.18 for longer than 6 seconds cumulatively, and will not exceed 1.10 for longer than 1 minute cumulatively.

  The technical basis for the V/Hz design parameter was developed through a review of relevant industry standards that include voltage and frequency limits for major electrical equipment. Low levels of overexcitation cause excessive core and non-magnetic structure heating, which can lead to loss of life and degradation of insulation. High levels of overexcitation can cause insulation failure within seconds.

  IEEE Standard C37.102 recommends generator V/Hz protection set to trip in 45 to 60 seconds at V/Hz greater than 1.10 per unit (pu), and in 2 to 6 seconds at V/Hz greater than 1.18 pu, and that the manufacturer's limitations should be respected. IEEE Standard C37.106 includes typical generator overexcitation limitation curves from various manufacturers which show time limits of roughly 60-100 seconds at 1.10 pu V/Hz, and 6 seconds or less at 1.20-1.30 pu V/Hz. IEEE Draft Standard PC37.91 includes typical curves from three manufacturers which show transformer limits of roughly 100 minutes at 1.10 pu, 1 minute at 1.20 pu, and 6 seconds at 1.30 pu.

  The performance requirements were selected to prevent equipment damage and to coordinate with generating unit protection. Protection coordination is critical to island survival since tripping of generation during underfrequency conditions may lead to cascading tripping and frequency collapse.

Coordination with Generation Underfrequency Tripping and Existing Settings

The SDT recognized the importance of coordination with generator underfrequency tripping. Accordingly, the drafting team choose the specific technical design parameter values in order to coordinate with a generator under (and over) frequency tripping characteristic that has been proposed for continent-wide use by the NERC standard drafting team addressing PRC-024 – Generator Verifications, and which that team has accepted for inclusion in its draft standard.

In addition to coordination with generator under and over frequency tripping, the drafting team also considered the existing regional UFLS set points and time delays in aggregate. The drafting team did not wish to force adjustments to UFLS relay settings and time delays simply to give the appearance of uniformity. There exists a degree of latitude over which the technical design parameters may vary and yet remain in coordination with the proposed generator tripping characteristics. Most existing regional UFLS programs should find conformance to the technical design parameters requires minimal or no adjustment of relay settings and time delays.

The above two factors, coordination with generator under and over frequency tripping as first priority, and then minimization of adjustments to existing relay settings, constituted the basis for choosing the technical design parameter values related to frequency.

Compliance with the regional standards will fulfill the intent of PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements, in that the performance characteristics will be detailed in the Regional Standards, along with associated compliance elements.

As for the event reporting required by PRC-009-0 — UFLS Performance Following an Underfrequency Event, the standard drafting team is recommending that this should be covered under the NERC Rules of Procedure and be included as a delegated responsibility for the Regional Entities as many other reporting tasks.

The following questions will assist the SDT in finalizing the development of the Under Frequency Load Shedding Regional Reliability Standard Characteristics. For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position. To improve the Under Frequency Load Shedding Regional Reliability Standard Characteristics, the SDT would appreciate responses to as many of these questions as you can answer.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

Characteristics of UFLS Regional Reliability Standards

1. The SDT determined that there is no need to have a continent-wide standard, and proposes that all UFLS requirements be contained within the regional UFLS standards developed in accordance with the Characteristics of UFLS Regional Reliability Standards.

   The SDT developed a set of characteristics which each of the regional entities will be directed to include in its UFLS regional reliability standard. The SDT developed these characteristics in an attempt to direct the regional entities to develop requirements

based on system performance, without prescribing specifics of how to meet the specified performance.

Do you agree with the drafting team?

- ☐ Yes
- ☐ No
- ☐ Yes and No
- ☐ Comments:

2. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must arrest frequency decline at no less than 58.0 Hz.

   Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

   ☐ Yes
   ☐ No – Delete the design parameter
   ☐ No – Revise the design parameter as noted in the comments
   Comments:

3. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that frequency does not remain below 58.5 Hz for greater than 10 seconds, cumulatively, and frequency does not remain below 59.5 Hz for greater than 30 seconds, cumulatively.

   Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

   ☐ Yes
   ☐ No – Delete the design parameter
   ☐ No – Revise the design parameter as noted in the comments
   Comments:

4. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that the frequency overshoot resulting from operation of UFLS relays will not exceed 61.0 Hz for any duration and will not exceed 60.5 Hz for greater than 30 seconds, cumulatively.

   Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

   ☐ Yes
   ☐ No – Delete the design parameter
   ☐ No – Revise the design parameter as noted in the comments
   Comments:

5. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that the Bulk Electric System voltage during and following UFLS operations is controlled such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than 6 seconds cumulatively, and does not exceed 1.10 for longer than 1 minute cumulatively.

   Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

   ☐ Yes
   ☐ No – Delete the design parameter
   ☐ No – Revise the design parameter as noted in the comments
   Comments:

6. If there are any other characteristics in the UFLS Regional Reliability Standard Characteristics document that you disagree with, please identify them here, and either identify that they should be deleted, or recommend an alternative.

   ☐ Agree with all proposed characteristics
   ☐ Disagree with one or more of the characteristics as noted in the comments
   Comments:

7. The SDT proposes that the regional standards include the database requirements contained in existing Reliability Standard PRC-007. Do you agree that database requirements should be addressed within the Regional Standards?

   ☐ Yes
   ☐ No
   ☐ Yes and No
   Comments:

8. Are you aware of any conflicts between the proposed regional standards and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

   ☐ Yes
   ☐ No
   ☐ Yes and No
   Comments:

9. Do you have any other questions or concerns with the proposed Under Frequency Load Shedding Regional Reliability Standard Characteristics that have not been addressed? If yes, please explain.

   ☐ Yes
   ☐ No
   ☐ Yes and No
   Comments:

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UFLS Regional Reliability Standard Characteristics

NERC, as the Electric Reliability Organization (ERO), will direct each Regional Entity to develop a regional reliability standard (Standard) with requirements for automatic Underfrequency Load Shedding (UFLS) programs. The regional Standards will require that UFLS programs arrest declining frequency and assist recovery of frequency following a frequency excursion. Each regional UFLS Standard shall specify, as a minimum, requirements that conform to the following:

1. The Standard shall specify the entity(s) responsible for determining the system boundaries and conditions for which the performance characteristics of item 4 below shall apply.

2. The Standard shall specify the entity(s) responsible for identifying potential islands within its region or between its region and neighboring regions for which the performance characteristics of item 4 below shall apply. The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS.

3. The Standard shall specify that the entity(s) responsible for identifying potential islands between its region and neighboring regions in item 2 above shall develop a procedure for coordinating with neighboring entities in identifying and reaching agreement on potential islands between its region and neighboring regions. The procedure shall identify how the neighboring entities will assist in the UFLS studies and analyses and provide concurrence of study results.

4. The Standard shall specify the technical design parameters required to meet the following performance characteristics for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions:

4.1. Arrest frequency decline at no less than 58.0 Hz.

4.2. Frequency shall not remain below 58.5 Hz for greater than 10 seconds, cumulatively, and shall not remain below 59.5 Hz for greater than 30 seconds, cumulatively.

4.3. Frequency overshoot resulting from operation of UFLS relays shall not exceed 61.0 Hz for any duration and shall not exceed 60.5 Hz for greater than 30 seconds, cumulatively.

4.4. Control Bulk Electric System voltage during and following UFLS operations such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than two seconds cumulatively, and does not exceed 1.10 for longer than 45 seconds cumulatively.

5. The Standard shall coordinate with PRC-024 Generator Performance During Frequency and Voltage Excursions by requiring that UFLS programs complete execution before generators begin to trip on underfrequency. Generator underfrequency trip settings are not subject to this directive.

6. The Standard shall specify how generators that are non-compliant with the PRC-024 underfrequency tripping requirement shall avoid jeopardizing UFLS effectiveness, or how

entities responsible for designing UFLS shall compensate for any non-compliant generators in their area to avoid jeopardizing UFLS effectiveness. The Standard shall require modeling of these method(s) in the UFLS assessment specified in item 10 below to ensure UFLS effectiveness is not jeopardized.

7. If the Regional Entity does not maintain its UFLS database, the Standard shall specify the entity(s) responsible for creating and maintaining a UFLS database. The Standard shall require that the responsible entity provide the UFLS database to the Regional Entity and NERC within 30 calendar days of a request.

8. The Standard shall specify the entity(s) responsible for providing data at least every five years to support maintenance of the database specified in item 7 above and shall specify what data to provide.

9. The Standard shall specify the entity(s) responsible for owning, installing, and setting UFLS equipment.

10. If the Regional Entity does not perform a UFLS assessment, including the following requirements, then the Standard shall specify the entity(s) responsible for performing a UFLS assessment.

10.1. The Standard shall require that the UFLS assessment shall verify through dynamic simulation that the implementation of the Standard is adequate to meet the performance characteristics in item 4 above for the system boundaries and conditions specified in accordance with item 1 above and for the identified islands specified in accordance with item 2 above.

10.2. The Standard shall require that the responsible entity conduct a UFLS assessment at least once every five years, and shall specify any conditions under which the responsible entity must conduct the assessment at more frequent intervals.

10.3. The Standard shall require that the responsible entity provide the assessment results to the Regional Entity and NERC within 30 calendar days of a request.

11. The Standard shall require that the entity(s) responsible for owning, installing, and setting UFLS equipment, in accordance with item 9 above, shall annually certify that the amount of load it expects to shed during a system event which results in system frequency excursions below the initializing set points of the regional UFLS standard.

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Standards Announcement

Comment Periods Open July 2, 2008

Now available at:
http://www.nerc.com/~filez/standards/Reliability_Standards_Under_Development.html

Comment Period for Project 2007-01 — Underfrequency Load Shedding Posted for 45-day Comment Period

The Underfrequency Load Shedding (UFLS) Standard Drafting Team has posted its initial draft of a set of characteristics for inclusion in regional underfrequency load shedding standards (Underfrequency Load Shedding Regional Reliability Standards Characteristics), along with an implementation plan for a 45-day comment period from July 2 through August 15, 2008.

Please use this electronic comment form to submit comments on the initial draft of the UFLS Regional Reliability Standards Characteristics and associated implementation plan by 8 p.m. (EDT) on **Friday, August 15, 2008.** If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

If you need an off-line, unofficial copy of the questions in the comment form, there is a copy of the comment form posted at the following site:

http://www.nerc.com/~filez/standards/Underfrequency_Load_Shedding.html

Comment Period for Project 2008-12 — SAR for Modifications to Coordinate Interchange Standards for Applicability and General Upgrade Opens July 2, 2008

The Standards Committee authorized posting a new SAR that addresses modifications to the set of Coordinate Interchange standards identified below for a 30-day comment period from July 2–31, 2008:

- INT-001-2 — Interchange Transaction Tagging
- INT-003-2 — Interchange Transaction Implementation
- INT-004-1 — Interchange Transaction Modifications
- INT-005-2 — Interchange Authority Distributes Arranged Interchange
- INT-006-2 — Response to Interchange Authority
- INT-007-1 — Interchange Confirmation
- INT-008-2 — Interchange Authority Distributes Status
- INT-009-1 — Implementation of Interchange
- INT-010-1 — Interchange Coordination Exemptions

The proposed modifications would clarify the applicability of the requirements, address issues raised by FERC, stakeholders and the Interchange Subcommittee, and bring the set of standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement program.

Please use this electronic comment form to submit comments on the SAR for modifications to Coordinate Standards and general updates by **July 31, 2008**. If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

If you need an off-line, unofficial copy of the questions in the comment form, there is a copy of the comment form posted at the following site:

http://www.nerc.com/~filez/standards/Project2008-12_Coordinate_Interchange_Stds_Modifications.html

Standards Development Process

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Comments on Underfrequency Load Shedding Characteristics

The Underfrequency Load Shedding Standard Drafting Team thanks all commenters who submitted comments on the UFLS Characteristics document. This document was posted for a 45-day public comment period from July 2, 2008 through August 15, 2008. The stakeholders were asked to provide feedback on the document through a special Electronic Standard Comment Form. There were 38 sets of comments, including comments from more than 100 different people from approximately 100 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/~filez/standards/Underfrequency_Load_Shedding.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
1.	Individual	Karl Kohlrus	City Water, Light & Power - Springfield, IL	1 - Transmission Owners, 3 - Load-serving Entities, 5 - Electric Generators
2.	Group	Guy Zito	NPCC	10 - Regional Reliability Organizations/Regional Entities

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Thompson	Consolidated Edison Co. of New York, Inc.	NPCC	1
2.	David Kiguel	Hydro One Networks Inc.	NPCC	1
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Frederick White	Northeast Utilities	NPCC	1
5.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
6.	Ron Falsetti	Independent Electricity System Operator	NPCC	2
7.	Kathleen Goodman	ISO - New England	NPCC	2

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
8.	Randy MacDonald	New Brunswick System Operator	NPCC	2
9.	Gregory Campoli	New York Independent System Operator	NPCC	2
10.	Michael Ranalli	National Grid	NPCC	3
11.	Ronald E. Hart	Dominion Resources, Inc.	NPCC	5
12.	Ralph Rufrano	New York Power Authority	NPCC	5
13.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
14.	Michael Gildea	Constellation Energy	NPCC	6
15.	Brian D. Evans-Mongeon	Utility Services	NPCC	6
16.	Donald E. Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
17.	Brian Hogue	NPCC	NPCC	10
18.	Alan Adamson	New York State Reliability Council	NPCC	10
19.	Guy Zito	NPCC	NPCC	10
20.	Lee Pedowicz	NPCC	NPCC	10
21.	Gerry Dunbar	NPCC	NPCC	10
3.	Individual	Edwin Averill	Grand River Dam Authority	5 - Electric Generators, 1 - Transmission Owners, 9 - Federal, State, Provincial Regulatory, or other Government Entities
4.	Group	Ken McIntyre	ERCOT	2 - RTOs and ISOs
5.	Individual	Don McInnis	Florida Power & Light	1 - Transmission Owners

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
6.	Individual	Vic. Baerg	Manitoba Hydro	1 - Transmission Owners, 5 - Electric Generators, 3 - Load-serving Entities, 9 - Federal, State, Provincial Regulatory, or other Government Entities, 6 - Electricity Brokers, Aggregators
7.	Individual	Thad Ness	American Electric Power (AEP)	6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners
8.	Group	Annette Bannon	PPL Generation	1 - Transmission Owners, 5 - Electric Generators, 6 - Electricity Brokers, Aggregators

Additional Member	Additional Organization	Region	Segment Selection	
1.	Mark Heimbach	PPL EnergyPlus	MRO	6
2.			NPCC	6
3.			RFC	6
4.			SERC	6
5.			SPP	6
6.	John Cummings	PPL EnergyPlus	WECC	6
7.	Joe Kisela	PPL Generation	RFC	5
8.			NPCC	5
9.	Tom Lehman	PPL Montana	WECC	5
10.	Dave Gladey	PPL Susquehanna	RFC	5
11.	Mike DeCesaris	PPL Electric Utilities	RFC	1
12.	Gabe Laczo	PPL Electric Utilities	RFC	1
13.	Gary Bast	PPL Electric Utilities	RFC	1
14.	Dave Price	PPL Electric Utilities	RFC	1

9.	Group	Lynn Schroeder	Southwest Power Pool (SPP UFLS Standard Drafting Team)	10 - Regional Reliability Organizations/Regional Entities
10.	Group	Brian Bartos	Bandera Electric Cooperative (TRE Regional UFLS Standard Drafting Team)	1 - Transmission Owners

Additional Member	Additional Organization	Region	Segment Selection	
1.	Dennis Kunkel	AEP	ERCOT	1
2.	Randy Jones	Calpine	ERCOT	5

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
3.		Matt Pawlowski	FPL Energy	ERCOT 5
4.		Rayborn Reader	EPCO	ERCOT 7
5.		Eddy Reece	Rayburn Country	ERCOT 1
6.		Barry Kremling	GVEC	ERCOT 1
7.		Sergio Garza	LCRA	ERCOT 1
8.		Steve Myers	ERCOT ISO	ERCOT 2
9.		Ken McIntryre	ERCOT ISO	ERCOT 2
11.	Individual	O. J. Brouillette	Louisiana Generqting, LLC	3 - Load-serving Entities, 5 - Electric Generators, 4 - Transmission-dependent Utilities, 1 - Transmission Owners
12.	Individual	Steve Harmath	Orrville Utilities	4 - Transmission-dependent Utilities
13.	Group	Marie Knox	Midwest ISO	2 - RTOs and ISOs

Additional Member	Additional Organization	Region	Segment Selection
1.	Kirit Shah	Ameren	SERC 1
2.	Jim Cyrulewski	JDRJC Associates	RFC 8

14.	Group	Jim Busbin	Southern Company Services, Inc	5 - Electric Generators, 1 - Transmission Owners

Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Wilson	Southern Company Services	SERC 1
2.	Terry Coggins	Southern Company Services	SERC 1
3.	Jonathan Glidewell	Southern Company Services	SERC 1
4.	Raymond Vice	Southern Company Services	SERC 1
5.	J. T. Wood	Southern Company Services	SERC 1
6.	Terry Crawley	Southern Company Services	SERC 5
7.	Marc Butts	Southern Company Services	SERC 1

15.	Individual	Mark Kuras	PJM	2 - RTOs and ISOs
16.	Group	Peter Heidrich	Florida Reliability Coordinating Council	1 - Transmission Owners, 4 - Transmission-dependent Utilities, 3 - Load-serving Entities, 10 - Regional Reliability Organizations/Regional Entities, 5 - Electric Generators

Additional Member	Additional Organization	Region	Segment Selection
1.	Jerry Murphy	Reedy Creek Improvement District	FRCC 3

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
2.		John Shaffer	Florida Power & Light	FRCC 1
3.		John Odom	FRCC	FRCC 10
4.		Fabio Rodriguez	Progress Energy	FRCC 1
5.		Don GIlbert	JEA	FRCC 5
6.		Alan Gale	City of Tallahassee	FRCC 5
7.		Don McInnis	Florida Power & Light	FRCC 1
8.		Art Nordlinger	Tampa Electric Company	FRCC 1
9.		FRCC System Protection & Control Subcommittee	FRCC	FRCC 10
17.	Group	Bob Jones	Southern Company Services, Inc. - Trans	1 - Transmission Owners

Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Foster	Ameren	SERC 1
2.	Anthony Williams	Duke Energy Carolinas	SERC 1
3.	Greg Davis	Georgia Transmission Corp.	SERC 1
4.	Ernesto Paon	Municipal Electric Authority of Georgia	SERC 1
5.	Andrew Fusco	NC Municipal Power Agency #1	SERC 1
6.	John O'Connor	Progress Energy Carolinas	SERC 1
7.	Pat Huntley	SERC Reliability Corp.	SERC 10
8.	Jonathan Glidewell	Southern Company Services, Inc. - Trans	SERC 1
9.	Tom Cain	Tennessee Valley Authority	SERC 1

18.	Individual	Kevin Koloini	Buckeye Power, Inc.	3 - Load-serving Entities, 4 - Transmission-dependent Utilities, 5 - Electric Generators
19.	Individual	Rick White	Northeast Utilities	1 - Transmission Owners
20.	Individual	Howard Rulf	We Energies	5 - Electric Generators, 4 - Transmission-dependent Utilities, 3 - Load-serving Entities
21.	Individual	John W Shaffer	Florida Power & Light Co.	1 - Transmission Owners
22.	Individual	Eric Mortenson	Exelon	1 - Transmission Owners, 3 - Load-serving Entities
23.	Individual	D. Bryan Guy	Progress Energy Carolinas, Inc.	3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners
24.	Individual	Kirit Shah	Ameren	6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 1 - Transmission Owners
25.	Group	Ken Goldsmith	Alliant Energy	4 - Transmission-dependent Utilities

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
		(MRO NERC Standards Review Subcommittee)		

Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS	MRO	3, 4, 5, 6
2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Jim Haigh	WAPA	MRO	1, 6
5.	Tom Mielnik	MEC	MRO	1, 3, 5, 6
6.	Pam Sordet	Xcel	MRO	1, 3, 5, 6
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
9.	Joseph Knight	GRE	MRO	1, 3, 5, 6
10.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
11.	Larry Brusseau	MRO	MRO	10
12.	Michael Brytowski	MRO	MRO	10

26.	Group	Brent Ingebrigtson	E.ON U.S.	6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners
27.	Individual	Kris Manchur	Manitoba Hydro	5 - Electric Generators, 6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 1 - Transmission Owners
28.	Group	Sandra Shaffer	PacifiCorp	1 - Transmission Owners, 5 - Electric Generators, 3 - Load-serving Entities

Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Viles	Transmission Technical Operations	WECC	1
2.	Kelly Johnson	Transmission Customer Service Engineering	WECC	1
3.	Terry Doern	Transmission Technical Operations	WECC	1
4.	Gregory Vasallo	Transmission Customer Service Engineering	WECC	1
5.	Stephen Hitchens	Transmission Technical Operations	WECC	1
6.	Rebecca Berdahl	Power Long Term Sales and Purchases	WECC	3

29.	Group	Denise Koehn	Transmission Reliability	3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners, 6 - Electricity Brokers,

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
			Program	Aggregators
30.	Individual	Ron Falsetti	Independent Electricity System Operator	2 - RTOs and ISOs
31.	Individual	Wayne Kemper	CenterPoint Energy	1 - Transmission Owners
32.	Group	Sam Ciccone	FirstEnergy Corp.	1 - Transmission Owners, 5 - Electric Generators, 3 - Load-serving Entities, 6 - Electricity Brokers, Aggregators

Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FirstEnergy	RFC 1, 3, 5, 6
2.	Dave Folk	FirstEnergy	RFC 1, 3, 5, 6
3.	Art Buanno	FirstEnergy	RFC 1
4.	Jim Detweiler	FirstEnergy	RFC 1
5.	Bob McFeaters	FirstEnergy	RFC 1
6.	Ken Dresner	FirstEnergy	RFC 5
7.	Bill Duge	FirstEnergy	RFC 5

33.	Group	Jason Shaver	American Transmission Company	1 - Transmission Owners
34.	Individual	Scott Berry	Indiana Municipal Power Agency	4 - Transmission-dependent Utilities
35.	Individual	Greg Rowland	Duke Energy	5 - Electric Generators, 6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 1 - Transmission Owners
36.	Group	Greg Davis	Georgia Transmission Corporation	1 - Transmission Owners
37.	Individual	Greg Ward / Darryl Curtis	Oncor Electric Delivery	1 - Transmission Owners
38.	Individual	Ed Davis	Entergy	
39.	Group	Robert Rhodes	Southwest Power Pool	1 - Transmission Owners, 2 - RTOs and ISOs, 3 - Load-serving Entities, 4 - Transmission-dependent Utilities, 5 - Electric Generators

Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Bateman	East Texas Electric Coop.	SPP 3, 4
2.	John Boshears	City Utilities of Springfield	SPP 1, 3, 5
3.	Brian Berkstresser	Empire District Electric	SPP 1, 3, 5
4.	Mike Gammon	Kansas City Power & Light	SPP 1, 3, 5

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)	
5.		Don Hargrove	Oklahoma Gas & Electric	SPP	1, 3, 5
6.		Danny McDaniel	CLECO	SPP	1, 3, 5
7.		Kyle McMenamin	Southwestern Public Service Company	SPP	1, 3, 5
8.		Eddy Reece	Rayburn Country Electric Coop	SPP	3, 4
9.		Robert Rhodes	Southwest Power Pool	SPP	2

1. The SDT determined that there is no need to have a continent-wide standard, and proposes that all UFLS requirements be contained within the regional UFLS standards developed in accordance with the Characteristics of UFLS Regional Reliability Standards. The SDT developed a set of characteristics which each of the regional entities will be directed to include in its UFLS regional reliability standard. The SDT developed these characteristics in an attempt to direct the regional entities to develop requirements based on system performance, without prescribing specifics of how to meet the specified performance. Do you agree with the drafting team?

Organization	Question 1:	Question 1 Comments:
City Water, Light & Power - Springfield, IL	Yes	In the Eastern Interconnection, it's probably good that not all regions shed load and the same frequencies. Doing so could lead to unstable conditions when the grid is already stressed.
NPCC	Yes	
Grand River Dam Authority	Yes	
ERCOT	Yes	
Florida Power & Light	Yes	
Manitoba Hydro	Yes	
American Electric Power (AEP)	Yes	
PPL Generation	Yes and No	PPL Corporation agrees with the SDT that a continent-wide standard is not practical and having the regional entities develop a process and appropriate requirements consistent with the "Characteristics of UFLS Regional Reliability Standards" is the most effective way to ensure a reliable transmission system. We also agree it is necessary for the standard to establish specific limits. However, rigid adherence to the stated characteristics may not be possible for certain generating facilities because of equipment limitations or manufacturer recommended over/under frequency protection requirements. Such limitations or requirements can not be ignored. As such, provisions to deviate from stated characteristics in these instances must be included in any regional entity standard developed. The expectation is that the generator would provide documentation as to why a specific characteristic can not be met and the regional entity would review the issue and determine if mis-coordination with the UFLS program exists. If mis-coordination does exist, the regional entity, with input from the host TO/TSP and the generator, would then be responsible for appropriate mitigation measures (i.e. shedding of additional load).
Southwest Power Pool	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not necessarily include those specific characteristics as requirements in the Regional Standard.
Bandera Electric Cooperative	Yes	The Texas Regional Entity Regional Underfrequency Standard Drafting Team (TRE UFLS SDT) agrees with the direction that the NERC team is proposing. Performance outcomes should be the focus of the regional standards development to allow for the proper integration of practices that have long been based on regional

Organization	Question 1:	Question 1 Comments:
		differences and practices. Those practices, where they obviously lend themselves to achieving the expected reliability outcomes, should be respected and incorporated in the development of these new regional standards.
Louisiana Generqting, LLC	Yes	
Orrville Utilities	Yes	
Midwest ISO	Yes and No	We agree with the drafting team's approach in developing a set of system characteristics rather than a continent wide standard. We are concerned though that when standards PRC-006, PRC-007, and PRC-009 are replaced that information and requirements could be lost that are important to UFLS. Regional standards drafting teams should review the content of these existing standards to determine what should be transferred to their standards. We believe that the characteristics are a good starting point and should set a minimum level of performance expected. The drafting team should consider whether there are any special systems (such as a peninsula) that may warrant different criteria and allow the regional standards to consider other criteria for those systems. To better assess the quality of the characteristics, the drafting team should provide the history behind these characteristics. Where did they come from? How were they derived? Did they come from old regional reliability organization (from MAIN, MAPP, ECAR, etc) criteria?
Southern Company Services, Inc	Yes	This approach allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
PJM	No	UFLS should be used as a safety net, based on installation requirements rather than performance requirements. As it is currently worded, if your UFLS load shedding does not arrest a blackout, you could potentially be found non-compliant.
Florida Reliability Coordinating Council	Yes	
Southern Company Services, Inc. - Trans	Yes	This approach allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	
We Energies	Yes	
Florida Power & Light Co.		
Exelon	No	This document, 'Characteristics of UFLS Regional Reliability Standards' is not a NERC Standard, yet it contains requirements for adherence by parties other than NERC or a Region. This new kind of requirement listing circumvents the Standard Development Procedure. It is not clear how this could ever be revised or what role stakeholders have in this. The creation of a new class of Standards creates confusion and is contrary to the

Organization	Question 1:	Question 1 Comments:
		well developed process that has been established. Why couldn't this be a NERC Standard, with all of the recognized checks and balances provided with that process, while at the same time leaving the few requirements that really need to be 'fill in the blank' up to a more detailed Regional Standard?
Progress Energy Carolinas, Inc.	Yes	This approach allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
Ameren	Yes and No	We agree that there is no need for a continent-wide UFLS standard. However, numerous system conditions would need to be studied to identify potential islands (Characteristic #2), and we doubt that the analyses to be performed would often accurately predict how the system would separate with any certainty. Also, it is likely that any separation would not be along company or regional lines. Therefore, we suggest that each region involve and coordinate neighboring regions in these studies and in the development of the regional UFLS standard and its requirements.
Alliant Energy	Yes and No	The MRO believes that the Regions should determine the details of the UFLS. We believe the regions are best situated to perform the studies and determine the total amount of load shed required, how many blocks, at what frequency, etc. This includes setting regional performance objectives for UFLS design, and deciding on generator under/over frequency minimum time delays and frequency setpoints. The MRO believes that the Under Frequency Load Shedding Standard Drafting Team is headed in the right direction as far as allowing the regions to create their own UFLS program within continental wide characteristics. It's the MRO's contention that while the 11 general characteristics are reasonable they may be too specific to accommodate the needs of every region or they may be too extreme for every region. The MRO asks that the UFLS SDT allow the regions a reasonable amount of time to determine the specific number which would accommodate the general NERC objectives but would address regional conditions. There are some inconsistencies in the document as the Characteristics listed in the "UFLS Regional Reliability Standard Characteristics" document do not match with those listed in this comment form in the "Characteristics of UFLS Regional Reliability Standards" section. Specifically, 1) What is the technical justification for the frequency overshoot limit of 61 Hz? (third bullet) 2) What is the technical justification for the time durations for the Volts/Hz? (Fourth Bullet) The MRO interprets that the STD is proposing the withdrawal of the PRC-006-0, PRC-007-0, and PRC-009-0 standards when applicable Regional replacement standard(s) are established and become effective. The MRO also interprets that the STD is proposing UFLS Regional Reliability Standard Characteristics, rather than revising the NERC UFLS standards, because NERC standards cannot be applicable to Regional Entities and the Characterizes may be a means for NERC to require the Regions to develop appropriate Regional standards that share key continent-wide characteristics.

Organization	Question 1:	Question 1 Comments:
		The MRO agrees that the existing NERC standards could be replaced with appropriate Regional standards and believe that some UFLS program requirements should be different in different Regions. The MRO disagrees that the Characteristics should direct Regional Entities to be based on continent-wide system performance values. Appropriate system performance levels and appropriate percentage of load shedding will vary for each potential island and depend on the composition of load, generation, and system protection within the island. The continent-wide Characteristics should deal with such broader issues such as: identification of potential islands, coordination among accountable entities, identification of appropriate load shedding percentage, identification and coordination with island-specific generation-related limits and system protection settings, responsibility for UFLS program design and implementation, responsibility for and frequency of UFLS program assessment, etc.
E.ON U.S.	Yes	
Manitoba Hydro	Yes and No	Manitoba Hydro agrees that region must have the flexibility to institute a UFLS that meets its region's topology requirements. Manitoba Hydro also agrees that the SDT should develop requirements based on system performance. However, the performance targets outlined in the characteristics document are not all appropriate for every region (specifics described in following comments).
PacifiCorp	Yes	
Transmission Reliability Program	Yes	
Independent Electricity System Operator	Yes	We support this approach
CenterPoint Energy	No	CenterPoint Energy believes this document has been issued for comments prematurely and recommends this effort be postponed until the proposed NERC Reliability Standard PRC-024 (Generator Protective System Performance During Frequency and Voltage Excursions) has been fully developed and vetted by all stakeholders through the NERC process. The prescriptive technical design characteristics proposed in these Characteristics of UFLS Regional Reliability Standards are based on parameters contained in the proposed PRC-024 that have not yet been issued to the industry for comments. It is premature to base these Characteristics on another standard that is still in the development process. As an alternative to postponing this effort, the proposed prescriptive technical characteristics could be deleted. While CenterPoint Energy proposes less restrictive characteristics in response to Questions 2, 3, and 4 below, our recommendation is that they be deleted or that Project 2007-1 be postponed. All the proposed technical design parameters appear to apply only for “underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent”. This characterization is simplistic and does not address all UFLS needs for other system conditions that can occur. The imbalance and response to an imbalance can vary dramatically considering not only the amount of generation that’s on-line, but also the type of generation on-line. System response will depend upon governor response and system inertia. For example, in order to arrest frequency decay for a 25% load / generation imbalance within prescribed parameters under certain conditions, a region may have to employ aggressive load

Organization	Question 1:	Question 1 Comments:
		shedding that might cause an overshoot beyond prescribed parameters under other conditions. This is especially true for regions that have significant penetration of wind energy, where system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions. The open ended requirement for arresting frequency after an initial imbalance of at least 25% could be interpreted to encompass imbalances of 50%, 75% or even 100% which is infeasible.
FirstEnergy Corp.	Yes and No	We agree with the SDT that there is no need for NERC to develop a continent-wide standard since there is already much work being done in some regions already creating their own regional standard. And we agree that NERC should at least specify the minimum expectations of UFLS programs needed by each region so that there is continent-wide consistency in the creation and implementation of regional UFLS standards. However, it is not clear how this document will be maintained in the NERC reliability standards realm. This document does not appear to have a standard number and version so that it can be maintained and used as a living document to be used as a reference for the minimum regional requirements. We are concerned that after these minimum regional characteristics are vetted through industry and subsequently used by the regions to create their initial versions of their region's UFLS standard, they will not be transparent to the regions years from now when they revise their standards. Additionally, at some point NERC and industry may determine the need to add and/or revise these minimum regional characteristics due to ever changing industry technology or methodologies regarding UFLS equipment design and utilization.
American Transmission Company	Yes and No	ATC interprets that the STD is proposing the withdrawal of the PRC-006-0, PRC-007-0, and PRC-009-0 standards when applicable Regional replacement standard(s) are established and become effective. ATC also interprets that the STD is proposing UFLS Regional Reliability Standard Characteristics, rather than revising the NERC UFLS standards, because NERC standards can not be applied to Regional Entities and the Characteristics may be a means for NERC to require the Regions to develop appropriate Regional standards that share key continent-wide characteristics. We agree that the existing NERC standards could be replaced with appropriate Regional standards and believe that some UFLS program requirements should to be different in different Regions. ATC disagrees that the Characteristics should direct Regional Entities to be based on continent-wide system performance values. Appropriate system performance values and appropriate percentage of load shedding will vary for each potential island and depend on the nature of load, generators, protection schemes, and dispatch within each island. The continent-wide Characteristics should deal with such broader issues such as: identification of potential islands, coordination among accountable entities, identification of appropriate load shedding percentage, identification and coordination with island-specific generation-related limits and system protection settings, responsibility for UFLS program design and implementation, , responsibility for and frequency of UFLS program assessment, the factors to be considered in assessments, etc.
Indiana Municipal Power Agency		
Duke Energy	Yes	

Organization	Question 1:	Question 1 Comments:
Georgia Transmission Corporation	Yes	This will allow each region to develop standards that meet the specific needs of their region
Oncor Electric Delivery	No	Oncor Electric Delivery does not believe that this document should be issued at this time. Many of the proposed design characteristics are based on parameters contained in the proposed NERC Reliability Standard PRC-024 which is still in the development stage. This document should be reissued for comments once PRC-024 has been approved.
Entergy	Yes and No	In general, we agree with the specifics prescribed by the drafting team and believe it is in the best interest of reliability to develop specific operating characteristics for each region. However, we do not agree with the design parameters set in section 4.
Southwest Power Pool	No	We have concerns that in eliminating the continent-wide standard we are also eliminating continent-wide enforcement and the common denominator that NERC provides through the reliability standards. Under the proposal, enforcement would apparently fall to each regional entity which could lead to inconsistency across an interconnection.

2. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must arrest frequency decline at no less than 58.0 Hz. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Organization	Question 2	Question 2 Comments:
City Water, Light & Power - Springfield, IL	Yes	
NPCC	Yes	We agree that arresting frequency decline at no less than 58.0 Hz is an appropriate design parameter in most interconnections to ensure coordination with the generator trip requirements to be proposed in PRC-024. However, in some interconnections such as Québec, where generator physical characteristics result in generator underfrequency trip settings below the curve to be proposed in PRC-024, Regional Reliability Standards should be allowed to permit exceptions to this design parameter.
Grand River Dam Authority	Yes	
ERCOT	Yes	Arresting frequency before 58.0Hz for at least 25% load/generation mismatch is a reasonable expectation.
Florida Power & Light	Yes	
Manitoba Hydro	Yes	
American Electric Power (AEP)	No Revise the design parameter as noted in the comments	The statement "the UFLS must arrest frequency decline at no less than 58.0 Hz" needs to be clarified. Is the intent of this characteristic to ensure an entity's UFLS scheme operates in its entirety prior to 58.0 Hz or is it to say that the system frequency must never drop below 58.0 Hz? In addition, the "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes.
PPL Generation	No Revise the design parameter as noted in the comments	Some existing generating facilities may have equipment limitations or specific protection issues which require the generator to trip at a frequency level above 58 Hz. This can result in a mis-coordination between the UFLS program and the generator protective settings. The 58 Hz value can be used as the guideline, but provision must be included to allow deviation from the guideline if mis-coordination of UFLS/Generator Frequency protective settings exist and valid technical reasons are provided by a legacy generating facility. See comment to question 1 for further details.
Southwest Power Pool	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not necessarily include those specific characteristics as requirements in the Regional Standard.
Bandera Electric Cooperative	Yes	In general, the TRE UFLS SDT believes a UFLS program development for recovery from a frequency excursion in an event that utilizes a 25% contribution within a system allowed to go no further than 58.0 Hz is reasonable. Further, we believe this set of parameters makes sense from the standpoint of the protection of certain equipment from sustained low frequency operation. The parameters are also viewed as essential to the protection of components of low pressure condensing turbines, which are very sensitive to low frequency operation and can quickly develop sub-standard frequency resonance conditions which can lead to catastrophic failures. The TRE UFLS SDT however does question the nature of the wording of the

Organization	Question 2	Question 2 Comments:
		performance criteria "...an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s)" Is the above stated incorrectly? Can the BES remain at a frequency greater than 58.0 Hz with a 25% imbalance between load and generation? Can generation maintain 125% loading without tripping and frequency collapse? Is the statement to imply that 25% of the load should be controlled by UFLS relays? Should the 25% be stated?
Louisiana Generqting, LLC	Yes	
Orrville Utilities	Yes	
Midwest ISO	No Revise the design parameter as noted in the comments	We understand that the 25% stated in the question represents the amount of load at system peak that could be shed by UFLS relays. If our understanding is correct, we support the design parameter and request that the drafting team make it clearer in the characteristics that this is based on system peak load. If not, we request the drafting to change the design parameter to match our understanding.
Southern Company Services, Inc	Yes	This is a reasonable parameter and apparently coordinates with the most recent thinking of the Generator Verification Standards Drafting Team.
PJM	No Revise the design parameter as noted in the comments	In Item 4, the statement “at least 25 percent” should be changed to “at most 25 percent”. As it is currently worded, the requirement is almost impossible to meet unless all load is on UFLS. We do not believe this was the intent of the drafting team. UFLS should be used as a safety net, based on installation requirements rather than performance requirements. As it is currently worded, if your UFLS load shedding does not arrest a blackout, you could potentially be found non-compliant.
Florida Reliability Coordinating Council	No Revise the design parameter as noted in the comments	The context of the phrase “identified island” requires clarification. We read the characteristics document to say the Regional Entity is required to develop a standard with UFLS that specifies the entity(s) responsible for identifying potential islands. We believe this means that the Regional Entity will name a group, such as the FRCC Stability Working Group to determine any islands that should meet the requirements of paragraph 2 in the characteristics document. However, we feel that the characteristic could potentially be misinterpreted as requiring the identification of ?any island? that has the possibility of being formed as the result of a system disturbance. It is not appropriate for these characteristics to require every possible island to meet the load mismatch criteria. The characteristics should make it clear that the program design should protect significant islands that could be created with credible multiple contingencies.
Southern Company Services, Inc. - Trans	Yes	This is a reasonable parameter and apparently coordinates with the most recent thinking of the Generator Verification Standards Drafting Team.
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	
We Energies	Yes	
Florida Power & Light Co.	No Revise the design parameter as noted in the comments	There may be low probability scenarios where islanding occurs with a load and generation imbalance significantly higher than 25%. The proposed wording could be interpreted to include any concievable combination of contingencies and operating conditions that leads to islanding. The words at least 25% should be replaced with up to 25%. Alternatively the words identified island(s) could be removed to prevent such an expansive interpretation.

Organization	Question 2	Question 2 Comments:
Exelon	No Revise the design parameter as noted in the comments	The wording in Requirement 4 is such that the phrase 'at least 25 per cent imbalance' should be changed to 'a maximum of 25 per cent imbalance'. There should be a size specification on 'identified island' such that it is meaningful to the bulk electric system.
Progress Energy Carolinas, Inc.	Yes	This is a reasonable parameter and, based on our understanding, apparently coordinates the most recent thinking of the Generator Verification Standards Drafting Team.
Ameren	No Revise the design parameter as noted in the comments	We agree that NERC should establish a minimum percentage of peak load that should be used for in design of UFLS. However, the NERC SDT should provide reasons for their recommendation. Again, we suggest that regions and subregions within the same interconnection should coordinate their UFLS design parameters.
Alliant Energy	No Revise the design parameter as noted in the comments	The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. Throughout NERC characteristic list, the words “conditions resulting from an imbalance between load and generation of at least 25%” are used in relation to stated performance objectives. The words “of at least” create confusion as well as the undefined term “imbalance”. The MRO has assumed this means that criteria must be met at the maximum overload level each Regions UFLS program is designed to cover, with all Regions having to shed a minimum of at least 25% of system load. However, this could also mean that criteria only has to be met for a 25% imbalance. This needs to be more clearly stated. The MRO agrees with the concept of NERC establishing a minimum load shedding level for all regions, but we do not know what a 25% imbalance is supposed to be. The definition of imbalance is not given but there is a definition that is common to the subject of UFLS, where overload = OL = (remaining generation — load)/(remaining generation). To us, imbalance = OL, then: OL = -.25 = (gen ? load)/gen = (.8-1)/.8 This implies 20% load shedding A 20% load shedding requirement seems a little low. A 25% minimum load shedding requirement seems more reasonable, but each Region would need to consider if that is adequate to satisfy their internal needs. In any event, minimum load shedding requirements should be explicitly stated as X% of load. The 58.0 Hz appears to have more of a philosophical basis rather than being solely related to generation protection needs. If generation protection is the issue, then a 58 Hz minimum frequency criteria would not be appropriate for all islands. An island consisting of hydro units could easily accept minimum frequencies below 58 Hz for extended periods. As a practical matter, 58 Hz, as average system frequency, is probably a reasonable minimum frequency target for design

Organization	Question 2	Question 2 Comments:
		work, at least for programs that shed 30% load or less. UFLS programs which need to shed more load can increase starting frequencies to improve the minimum frequency to some extent, but may need to accept momentary dips below 58 Hz provided this coordinates with overall generation protection. If this becomes NERC performance criteria, then we anticipate there needs to be a way to allow exceptions when appropriate. We also have concerns that minimum frequency seen in simulations is quite subjective, it depends on many specific details such as the specific overload level modeled, as well as the assumptions made for load damping, system inertia, UFLS details including total tripping times of load, capacitor tripping, governor response, etc. It is easier at the Regional level to resolve what range of conditions/assumptions/modeling issues need to be considered. If any generators have unreasonable frequency characteristics that can be changed, then the Standard should require them to make appropriate changes.
E.ON U.S.	No Revise the design parameter as noted in the comments	See Response to Question 9.
Manitoba Hydro	No Revise the design parameter as noted in the comments	While 58 Hz may be appropriate for thermal units, hydro units can operate at lower frequencies. Manitoba Hydro's system is predominantly hydro units, and given our system topology, a 58 Hz cut off is not appropriate to balance our load and generation when our system is separated from the BES. There should be some provision made for systems that are not tightly interconnected with the rest of the BES. Coordination of UFLS and generator protection within the region would then become a very important component of this performance metric.
PacifiCorp	Yes	Location of generation, load centers and associated transmission interconnections between specific geographical area impact the UFLS study results, especially in WECC region. It would be helpful if RRO would identify credible islands (bubbles) for UFLS studies within RRO and designate responsible parties to conduct overall UFLS studies as per PRC-006.
Transmission Reliability Program	Yes	
Independent Electricity System Operator	Yes	
CenterPoint Energy	No Delete the design parameter	As stated previously, CenterPoint Energy believes this effort should be postponed. Alternatively, this proposed design parameter should be deleted until coordination with the PRC-024 drafting team can be firmly established. If the design parameter is not deleted, CenterPoint Energy recommends a value of 57.5 Hz instead of 58.0 Hz to place proper balance and emphasis on system reliability as system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions.
FirstEnergy Corp.	No Revise the design parameter as noted in the	The document should be revised to indicate imbalances of "25 percent or less" instead of "at least 25%". If a condition occurred that resulted in a very large imbalance, perhaps much greater than 50%, it may not be possible to arrest the frequency decline to no less than 58 Hz.

Organization	Question 2	Question 2 Comments:
	comments	
American Transmission Company	No Revise the design parameter as noted in the comments	With respect to the 25 percentage (Characteristic 4), rather than base UFLS program requirements on system conditions that may have variable underlying assumptions, a better approach might be to specify that UFLS programs be required to shed a minimum percentage of potential island load. In addition, the term, "imbalance between load and generation condition", is ambiguous and not clearly defined. Requiring ULFS programs be designed to shed at least a specified percent of potential island load is suggested. We interpret that the phrase "at least" implies that some Regional standards may require a higher percentage for different potential islands depending on the nature of load, generators, protection schemes, and dispatch within the island. With respect to the 58.0 Hz value (Characteristic 4.1), we agree that this value seems reasonable in general. However, for some potential islands the appropriate frequency limit might be higher or lower than 58.0 Hz based on the nature of the load, generators, protection schemes, and dispatch in the island. An absolute, continent-wide value may not be appropriate. The Characteristics could require that the proper frequency limit be investigated and established for each potential island. The proper frequency limit should be re-examined and changed, if necessary, each time the UFLS program for a potential island is re-assessed. If any generator limitations cause an unreasonable frequency limit and any of these limitations can be changed, then the Standard should require the Generator Owner to make appropriate changes.
Indiana Municipal Power Agency		
Duke Energy	Yes	
Georgia Transmission Corporation	Yes	
Oncor Electric Delivery		
Entergy	Yes	This is a reasonable parameter and apparently coordinates with the most recent thinking of the Generator Verification Standards Drafting Team.
Southwest Power Pool	Yes	Our understanding is that we would continue to use a multi-step UFLS scheme similar to what is being utilized today and that drastic changes to these existing schemes would be avoided.

3. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that frequency does not remain below 58.5 Hz for greater than 10 seconds, cumulatively, and frequency does not remain below 59.5 Hz for greater than 30 seconds, cumulatively. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Organization	Question 3	Question 3 Suggested Revisions:
City Water, Light & Power - Springfield, IL	Yes	
NPCC	Yes	
Grand River Dam Authority	No – Revise the design parameter as noted in the comments	What is the definition of cumulatively? Is this from the start of the event (UF), or is during the previous number of minutes, or from the beginning of time? It would appear that a better choice of a word is in order. What does the load imbalance have to do with the UF decision? You either have UF or you do not, regardless of load imbalance. Or is there an intent to take no action on an UF event if there is a load imbalance less than 25%.
ERCOT	No – Revise the design parameter as noted in the comments	Operating to these design parameters seems reasonable. However, maybe the NERC standard characteristic should enforce the Region to have a methodology for determining these levels, Regional Standard should have the methodology for setting the levels to be met. Alternatively, the standard characteristic requirement should specify parameters for each Interconnection that are more technically suitable to the characteristic of each Interconnection.
Florida Power & Light	No – Revise the design parameter as noted in the comments	The term cumulatively is not defined. How is this measured? Is this over the time of the event, over the life of equipment i.e. generators etc.
Manitoba Hydro	Yes	
American Electric Power (AEP)	No – Revise the design parameter as noted in the comments	Most UFLS schemes are designed to meet the time requirements proposed by this characteristic if the load/generation imbalance is 25% or less. If the load/generation imbalance is greater than 25%, manual operator intervention (load shedding) may be required to maintain system frequency. An operator can not meet the time requirements outlined by this characteristic. The "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes.
PPL Generation	No – Revise the design parameter as	See comments to question 1.Some existing generating facilities may have equipment limitations or specific protection issues which force the generator to trip at a frequency levels and operating times that are inconsistent with the characteristic identified above. This can result in a mis-coordination between the UFLS program and the

Organization	Question 3	Question 3 Suggested Revisions:
	noted in the comments	generator protective settings. The above characteristic can be used as the guideline, but provision must be included to allow deviation from the guideline if mis-coordination of UFLS/Generator Frequency protective settings exist and valid technical reasons are provided by a legacy generating facility.
Southwest Power Pool	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not necessarily include those specific characteristics as requirements in the Regional Standard.
Bandera Electric Cooperative	No – Revise the design parameter as noted in the comments	The TRE UFLS SDT recommends the NERC performance criteria be revised from 59.5 Hz to 59.3 Hz. 59.5 Hz is a frequency level that should be supported by high set relays, (59.7 Hz); and when high sets are activated, the next level of intervention should be 59.3 Hz for no more than 30 seconds.
Louisiana Generqting, LLC	Yes	
Orrville Utilities	Yes	
Midwest ISO	No – Revise the design parameter as noted in the comments	We understand that the 25% stated in the question represents the amount of load at system peak that could be shed by UFLS relays. If our understanding is correct, we support the design parameter and request that the drafting team make it clearer in the characteristics that this is based on system peak load. If not, we request the drafting to change the design parameter to match our understanding. These design parameters should be coordinated with typical turbine operating characteristics. The UFLS relays should shed load to prevent permanent turbine damage. It is our understanding that a typical turbine can operate at 59.5 Hz for 30 minutes rather than 30 seconds without experiencing loss of life. Was the 30 seconds at 59.5 Hz supposed to be 30 minutes? What does cumulative mean here? Is it the total operating time over a week period, a day, a year, the life of turbine? If the system frequency dips below 59.5 Hz for 15 minutes today and dips below 59.5 Hz tomorrow for 15 minutes, does that mean the UFLS relays should operate?
Southern Company Services, Inc	Yes	No Additional Comment.
PJM	No – Revise the design parameter as noted in the comments	Please refer to the comment above for question 2. The current draft RFC standard allows the first step of UFLS to begin at 59.3 Hz. Please consider reducing this requirement to 59.3 Hz in the NERC Standard. When discussing cumulatively, when is the accumulation timer reset: after a minute, an hour, a year?
Florida Reliability Coordinating Council	No – Revise the design parameter as noted in the	Remove of the word ?cumulatively? as it is undefined and could be interpreted in several ways, but we think the intent was for a consecutive time. We believe protection engineers would interpret the times as an inclusive time frame and not as a cumulative period beyond the time span given.The context of the phrase ?identified island? requires clarification. (See comments for Question No. 2.)

Organization	Question 3	Question 3 Suggested Revisions:
	comments	
Southern Company Services, Inc. - Trans	Yes	
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	
We Energies	Yes	
Florida Power & Light Co.	No – Revise the design parameter as noted in the comments	The meaning of the term cumulatively in this context is unclear. If redefined as specific to one event, it would still be an unnecessary qualifier that would be difficult to apply. Remove the term cumulatively
Exelon	No – Revise the design parameter as noted in the comments	RFC has determined and included in its draft standard that the first step of the UFLS program may be at 59.3 Hz. Please change the parameter to include RFC level.
Progress Energy Carolinas, Inc.	No – Revise the design parameter as noted in the comments	This design parameter is appropriate except for the requirement to "not remain below 59.5 Hz for greater than 30 seconds." Relatively quick recovery above 58.5 is appropriate to minimize the possibility of generator trips. However, at 59.5 Hz, the possibility of generator trips is greatly reduced and a more reasonable recovery time should be allowed. Recommend this be changed to "not remain below 59.5 Hz for greater than 5 minutes." ANSI standard 37.106-2003 indicates that 59.5 Hz for 5 minutes provides adequate margin above typical generator damage curves. This change will help reduce the potential for overshoot while still providing sufficient margin. Additionally, the word "cumulatively" (in Characteristics 4.3 and 4.4) should be removed. Cumulatively refers more to "cumulative machine damage" and is not easily tracked on a system level (nor is it necessary on a system level).
Ameren	No – Revise the design parameter as noted in the comments	We believe that the proposed time for underfrequency operation is too restrictive. The proposed time of 30 seconds of operation at 59.5 Hz does not provide the system operators with enough time to attempt to bring generation on-line to remedy the frequency undershoot. Based on our practices, tripping of generation at 59.5 Hz is not necessary and if implemented may further exacerbate the frequency decline conditions. We agree that underfrequency operation is neither optimum nor desired, but the system needs to hold together as long as possible to be able to implement operational solutions. We suggest that the SDT to quantify the risks, including appropriate review of existing (not proposed) IEEE, ANSI and other standards, associated with operating the

Organization	Question 3	Question 3 Suggested Revisions:
		generating equipment at 59.5 Hz (0.992 p.u.) for more than 30 seconds to support their recommendation. We also suggest the SDT to clearly define the term "cumulatively"; For example, is it per event, per life of the equipment, or something else?
Alliant Energy	No – Revise the design parameter as noted in the comments	The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. We do not agree with the specified maximum operating times associated with the specified off-nominal frequencies. The proposal to limit time below 59.5 Hz and above 60.5 Hz to 30 seconds looks like a typo. 59.5 Hz to 60.5 Hz is the range where units can run continuously with no accelerated loss of life. Perhaps “30 seconds” should have read “30 minutes” which is still only 66% of the time specified by the MRO program for f <= 59.5 Hz. As written, the proposed criteria for time spent below 59.5 Hz and above 60.5 Hz is unacceptable. The MRO UFLS report states that generation protection cannot trip any quicker than shown below, and that utilities that need to shed more than 30% of connected load will have to relax these times to allow their load shedding to play out. MRO generation protection time delay requirement: • 45 minute, frequency <=59.5 Hz? • 5 minute, frequency <= 59.3 Hz? • 1.33 minute, frequency <= 59 Hz? • 30 second, frequency <= 58.4 Hz? • 7.5 second, frequency <= 58.0 Hz? • instant trip at 57.6 Hz In the MRO UFLS study simulations, we estimated our worst-case time below 58.5 Hz would be approximately 9 seconds. Of course, this has to be qualified by saying “for our given assumptions”. These types of simulations only give approximate results. The proposal to limit time below 58.5 Hz to 10 seconds is going to be tight for a program which sheds more than 30% load. What we assume for governor action will have considerable effect on how much time is spent below 58.5 Hz. The MRO tried to design a program that will ensure frequency recovery even if we get no net governor response.

Organization	Question 3	Question 3 Suggested Revisions:
		The MRO study looked at a range of imbalances that an UFLS program has to respond to, and factored in uncertainties. 100?s of cases were run to cover a range of imbalances, range of damping assumptions, and a range of system based inertia. In looking at all of the results in total, the resulting time spent below a given frequency took on the form of a probability density function. Typical times below a given frequency are perhaps more representative of what the typical exposure is for generation. However we coordinated generation protection according to the worst case times with enough margin to provide a degree of comfort. The actual loss of life a generator will be exposed to for some arbitrary UFLS event will most often be less than what these generator protection trip settings reflect as the first line of defense is the load shedding program itself. Under most circumstances, we will never spend enough time in the frequency trip bands to actually trip generation. To view the full report of the MRO UFLS please see the MRO website:http://www.midwestreliability.org/03_reliability/assessments/report_draft_03_12_final_clean.pdf
E.ON U.S.	No – Revise the design parameter as noted in the comments	See Response to Question 9.
Manitoba Hydro	No – Revise the design parameter as noted in the comments	Manitoba Hydro echo's the MRO's concerns: "The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. "
PacifiCorp	Yes	same comment as item 2 to identify UFLS study bubble by RRO.
Transmission Reliability Program	Yes	
Independent Electricity System Operator	Yes	
CenterPoint Energy	No – Delete the design parameter	As stated previously, CenterPoint Energy believes this effort should be postponed. Alternatively, this proposed design parameter should be deleted until coordination with the PRC-024 drafting team can be firmly established. If the design parameter is not deleted, CenterPoint Energy recommends the following values to place proper balance and emphasis on system reliability as system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions: 58.4 Hz to 59.4 Hz for up to 9

Organization	Question 3	Question 3 Suggested Revisions:
		minutes and continuous above 59.4 Hz.
FirstEnergy Corp.	No – Revise the design parameter as noted in the comments	1. Although we agree that there needs to be a low set-point duration of no greater than 10 seconds for frequencies below 58.5 Hz, we are not sure if the appropriate first set-point should be set at 59.5 Hz. Some systems may be able to function reliably at 59.4 Hz for more than 30 seconds, so we ask the SDT to investigate this or provide the technical rationale for choosing 59.5 Hz.2. When using the term "cumulatively" in this characteristic, when is the accumulation timer reset: a minute, an hour, a year? We are not clear if this is based on a design parameter or an "after-the-fact" performance review. We ask the SDT to provide clarification on this term.3. As stated previously, the document should be revised to indicate imbalances of "25 percent or less" instead of "at least 25%". The design parameters would not be achievable if an extremely high imbalance occurred.
American Transmission Company	No – Revise the design parameter as noted in the comments	With respect to the 25 percentage (Characteristic 4), refer to comments for Question 2.With respect to the 10-second and 30-second underfrequency values (Characteristic 4.2), these values may be reasonable in general. However, for some potential islands the appropriate frequency limits might be higher or lower based on the nature of the load, generators, protection schemes, and dispatch in the island. Absolute, continent-wide values may not be appropriate. The Characteristics could require that the proper frequency limits be investigated and established for each potential island. The proper frequency limit should be re-examined and changed, if necessary, each time the UFLS program for a potential island is re-assessed. If any generator limitations cause an unreasonable frequency limit and any of these limitations can be changed, then the Standard should require the Generator Owner to make appropriate changes.
Indiana Municipal Power Agency	No – Revise the design parameter as noted in the comments	The term cumulatively is confusing. It either needs to be clarified or removed.
Duke Energy	No – Revise the design parameter as noted in the comments	The time frames stated in these criteria seem overly conservative. Thirty seconds at 59.5 Hz would likely create expensive and unnecessary relay setting changes. Recommend changing the requirement to "59.5 Hz for greater than 5 minutes." The Generator Verification SDT (PRC-024) is evaluating the appropriate envelope for protection of generator equipment. The envelope established by these criteria must be coordinated with generator protection envelope. The word "cumulatively" is confusing in this context. Since this is generally related to equipment and not system studies, recommend deleting "cumulatively" from the requirements.
Georgia Transmission Corporation	Yes	
Oncor Electric Delivery		

Organization	Question 3	Question 3 Suggested Revisions:
Entergy	No	Entergy experiences some under-frequency relay trips due to transient contributions from induction motors with UF relays set to trip at 59.3 Hz. Relay trip settings at 59.5 Hz will increase the likelihood of these nuisance trips with attendant two-hour restart times for large commercial / industrial loads. We suggest the 59.5 Hz, 30 second, requirement is an overly restrictive requirement and we believe the setting should be lowered to at least 59.3 Hz. Lowering this requirement will give regions greater latitude when developing the design requirements of their standard.
Southwest Power Pool		

4. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that the frequency overshoot resulting from operation of UFLS relays will not exceed 61.0 Hz for any duration and will not exceed 60.5 Hz for greater than 30 seconds, cumulatively. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Organization	Question 4	Question 4 Suggested Revisions:
City Water, Light & Power - Springfield, IL	Yes	
NPCC	No – Revise the design parameter as noted in the comments	We agree this design parameter is appropriate as an overall system design objective. However, this objective cannot be met through the UFLS program design alone in the absence of adequate generating unit governing response. We recommend that applicability of this design parameter be limited to islands that exhibit a frequency response of at least 1 percent of peak island load per 0.1 Hz.
Grand River Dam Authority	Yes	
ERCOT	No – Revise the design parameter as noted in the comments	Operating to these design parameters seems reasonable. However, maybe the NERC standard characteristic should enforce the Region to have a proof of methodology of determining these levels, Regional Standard should have the methodology for setting the levels to be met. Alternatively, the standard characteristic requirement should specify parameters for each Interconnection that are more technically suitable to the characteristic of each Interconnection. In addition to the comment; does the NERC SDT have supporting documentation for restricting frequency overshoot to 61Hz? Request NERC Generation Verification SDT for reasoning/explanation.
Florida Power & Light	No – Revise the design parameter as noted in the comments	Cumulatively needs to be defined. Is this cumulative over the event, cumulatively over the life of the equipment? The 61Hz and 60.5Hz limits are overly restrictive and do not appear to coordinate with any equipment limitations
Manitoba Hydro	Yes	
American Electric Power (AEP)	No – Revise the design parameter as	UFLS schemes are designed to account for frequency overshoot by breaking the UFLS scheme up into separate steps (verified by dynamic simulation). Is the intent of this characteristic to specify parameters for the amount of load included in each UFLS step and/or to specify parameters for unit overspeed trip settings? Clarification is

Organization	Question 4	Question 4 Suggested Revisions:
	noted in the comments	needed not only for the intent of this characteristic but also regarding the foundation of the timing requirements. In addition, the "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes.
PPL Generation	No – Revise the design parameter as noted in the comments	See comments to question 1.Some existing generating facilities may have equipment limitations or specific protection issues which force the generator to trip at a frequency levels and operating times that are inconsistent with the values identified above. This can result in a mis-coordination between the UFLS program and the generator protective settings. The above characteristic can be used as the guideline, but provision must be included to allow deviation from the guideline if mis-coordination of UFLS/Generator Frequency protective settings exist and valid technical reasons are provided by a legacy generating facility.
Southwest Power Pool	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not necessarily include those specific characteristics as requirements in the Regional Standard.
Bandera Electric Cooperative	No – Delete the design parameter	The TRE UFLS SDT believes that the NERC standard should not define the frequency overshoot limit; instead, the NERC standard should state this as a requirement for the region to establish as part of a regional UFLS standard. For example, the NERC standard might state as follows: "The Regional Standard shall define the frequency overshoot it determines appropriate in arresting the imbalance between load and generation."
Louisiana Generqting, LLC	No – Revise the design parameter as noted in the comments	61Hz and 60.5Hz limits are overly restrictive and do not appear to coordinate with any equipment limitations
Orrville Utilities	Yes	
Midwest ISO	No – Revise the design parameter as noted in the comments	We understand that the 25% stated in the question represents the amount of load at system peak that could be shed by UFLS relays. If our understanding is correct, we support the design parameter and request that the drafting team make it clearer in the characteristics that this is based on system peak load. If not, we request the drafting to change the design parameter to match our understanding. These design parameters should be coordinated with typical turbine operating characteristics. If a turbine can operate at 60.5 Hz for 30 minutes before experiencing any loss of life, the design parameters should reflect this. It is our understanding that a typical turbine can operate at 60.5 Hz for 30 minutes rather than 30 seconds without experiencing loss of life. Was the 30 seconds at 60.5 Hz supposed to be 30 minutes?
Southern Company Services, Inc	No – Revise the design parameter as noted in the comments	These parameters are overly restrictive. We recommend to change the statement to "will not exceed 61.5 Hz for any duration and will not exceed 60.5 Hz for greater than 5 minutes?" A frequency of 61.8 Hz results in a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin. ANSI standard 37.106-2003 indicates that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. Our proposed parameters allow time for generator governors to operate and for some load restoration to

Organization	Question 4	Question 4 Suggested Revisions:
		correct overshoot.
PJM	No – Revise the design parameter as noted in the comments	"for any duration" is too difficult to meet. Substitute with a short time frame.
Florida Reliability Coordinating Council	No – Revise the design parameter as noted in the comments	The 61.0 hertz ceiling for frequency recovery seems too low. Is there any technical justification for this level? A more appropriate limit might be 61.8 hertz due to the number of governing systems that initiate auxiliary governor action at 103% overspeed. Remove of the word “cumulatively”. (See comments for Question No. 3.)The context of the phrase “identified island” requires clarification. (See comments for Question No. 2.)
Southern Company Services, Inc. - Trans	No – Revise the design parameter as noted in the comments	These parameters are overly restrictive. We recommend to change the statement to "will not exceed 61.5 Hz for any duration and will not exceed 60.5 Hz for greater than 5 minutes?" A frequency of 61.8 Hz results in a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin. ANSI standard 37.106-2003 indicated that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. Our proposed parameters allow time for generator governors to operate and for some load restoration to correct overshoot.
Buckeye Power, Inc.	Yes	
Northeast Utilities	No – Revise the design parameter as noted in the comments	We do not believe all generator controls are sufficiently responsive to enable this design parameter. A longer response time may be needed, or a significant improvement in governing response for connected generators.
We Energies	Yes	
Florida Power & Light Co.	No – Revise the design parameter as noted in the comments	A technical justification of the proposed over frequency limits does not appear to be posted with the generator verification SDT information. A target over frequency limit of 61.8 hertz is used within the FRCC. The 61.0 hertz and 60.5 hertz for 30 seconds appear to be unnecessarily low. The words at leat 25% should be replaced with up to 25% for the reasons discussed above. The word cumulatively should be removed.
Exelon	No – Revise the design parameter as noted in the comments	There should be a distinction and differing requirements between the entire Eastern Interconnection and a potential frequency overshoot in a much smaller identified island. Also, the minimum size of the postulated island should be specified here. It should be of sufficient size to affect the bulk electric system.

Organization	Question 4	Question 4 Suggested Revisions:
Progress Energy Carolinas, Inc.	No – Revise the design parameter as noted in the comments	These parameters are overly restrictive. We recommend to change the statement to "will not exceed 61.5 Hz for any duration and will not exceed 60.5 Hz for greater than 5 minutes?" A frequency of 61.8 Hz results in a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin.ANSI standard 37.106-2003 indicated that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. Our proposed parameters allow time for generator governors to operate and for some load restoration to correct overshoot.
Ameren	No – Revise the design parameter as noted in the comments	We believe that these overfrequency parameters are overly restrictive. We suggest that the SDT to quantify the risks, including appropriate review of existing (not proposed) IEEE, ANSI and other standards, associated with operating the generating equipment above 60.5 Hz for more than 30 seconds to support their recommendation. We also suggest the SDT to clearly define the term "cumulatively"; For example, is it per event, per life of the equipment, or something else?
Alliant Energy	No – Revise the design parameter as noted in the comments	This a subjective performance criteria as modeling details such as load damping assumptions, inertia assumptions, and governor response assumption will all have considerable effect on performance. This type of performance objective is best evaluated and determined at the Regional level, or some mechanism needs to be in place to allow aggressive load shedding programs some latitude on this. There are cases where overshoots above 61 Hz could be accepted for short periods. The type of units in the island also have to be considered. Hydro systems have fewer off-nominal frequency restrictions. The 30 second time limit for operating above 60.5 Hz is not at all appropriate. Units can operate continuously at 60.5 Hz with no accelerated loss of life. They can run slightly above this for a long time. Could this be a typo? Was the intention to establish at 30 minute limit?
E.ON U.S.	No – Revise the design parameter as noted in the comments	See Response to Question 9.
Manitoba Hydro	No – Revise the design parameter as noted in the comments	Again, Manitoba Hydro echo's the MRO's concerns. Each region should determine the maximum overshoot based on its system topology, how it was planned and designed and the region's requirements.
PacifiCorp	Yes	
Transmission Reliability Program	Yes	

Organization	Question 4	Question 4 Suggested Revisions:
Independent Electricity System Operator	Yes	
CenterPoint Energy	No – Delete the design parameter	As stated previously, CenterPoint Energy believes this effort should be postponed. Alternatively, this proposed design parameters should be deleted until coordination with the PRC-024 drafting team can be firmly established. If the design parameter is not deleted, CenterPoint Energy recommends a value of 61.5 Hz instead of 61.0 Hz to place proper balance and emphasis on system reliability as system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions.
FirstEnergy Corp.	No – Delete the design parameter	1. When using the term "cumulatively" in this characteristic, when is the accumulation timer reset: a minute, an hour, a year? We are not clear if this is based on a design parameter or an "after-the-fact" performance review. We ask the SDT to provide clarification on this term.2. We recommend that this design parameter be deleted. We feel that the characteristic is overly prescriptive. Although frequency overshoot may be a concern in some regions, it is not in all regions. In many regions the generators would automatically re-adjust to lower frequency.
American Transmission Company	No – Revise the design parameter as noted in the comments	With respect to the 25 percentage (Characteristic 4), refer to comments for Question 2.With respect to the continuous and 30-second overfrequency values (Characteristic 4.3), these values may be reasonable in general. However, for some potential islands the appropriate frequency limits might higher or lower based on the nature of the load, generators, protection schemes, and dispatch in the island. Absolute, continent-wide value may not be appropriate. The Characteristics could require that the proper frequency limit be investigated and established for each potential island. The proper frequency limit should be re-examined and changed if necessary each time the UFLS program for a potential island is re-assessed. If any generator limitations cause an unreasonable frequency limit and any of these limitations can be changed, then the Standard should require the Generator Owner to make appropriate changes.
Indiana Municipal Power Agency	No – Revise the design parameter as noted in the comments	The term cumulatively is confusing. It either needs to be clarified or removed.
Duke Energy	No – Revise the design parameter as noted in the comments	These parameters seem too restrictive. Recommend changing the statement to "will not exceed 61.5 Hz for any duration and will not exceed 60.5 Hz for greater than 5 minutes?" This is recommended because a frequency of 61.8 Hz is a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin. Also, ANSI standard 37.106-2003 indicated that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. the recommended parameter changes allow time for generator governors to operate and for some load restoration to correct overshoot.
Georgia	Yes	

Organization	Question 4	Question 4 Suggested Revisions:
Transmission Corporation		
Oncor Electric Delivery		
Entergy	No	We agree with and support the SERC comments.
Southwest Power Pool		

5. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that the Bulk Electric System voltage during and following UFLS operations is controlled such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than 6 seconds cumulatively, and does not exceed 1.10 for longer than 1 minute cumulatively. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Organization	Question 5	Question 5 Suggested Revisions:
City Water, Light & Power - Springfield, IL		
NPCC	Yes	
Grand River Dam Authority	No – Revise the design parameter as noted in the comments	This seems to be out of place in an UFLS scheme and may belong in an OV scheme. As load is rejected to correct the frequency problem, the voltage should climb. The generators, with the VRs, may or may not see the problem. This seems more like a hope than an item that someone can accomplish. Studies may indicate that there is no problem. But if they show a problem, what can be done? Install shunt reactors which may not help the frequency problem????
ERCOT	No – Revise the design parameter as noted in the comments	Is this just a planning characteristic for simulation of the UFLS, or a post event measurement for compliance? If it is included in the post event compliance analysis then it needs to be more specific on what voltage(s) are to be measured and meet the design parameters. Is it every Bus Voltage in the BES? Or a subset of critical buses for measurement? Perhaps the NERC Standard Characteristic requests that each Region establish a methodology for determining a list of critical buses and these bus voltages are to be used for the UFLS and post event compliance analysis. Alternatively, the standard characteristic requirement should specify how to determine which buses to which these voltage requirements apply for each Interconnection, at a minimum, and preferably for each Region.
Florida Power & Light	No – Revise the design parameter as noted in the comments	The term cumulatively needs to be defined
Manitoba Hydro	Yes	
American Electric Power (AEP)	No – Delete the design parameter	The foundation of the timing requirements needs to be clarified. In addition, the "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes.

Organization	Question 5	Question 5 Suggested Revisions:
PPL Generation	Yes	UFLS scheme should adhere to the IEEE standards for machines.
Southwest Power Pool	No – Delete the design parameter	The UFLS system consists of underfrequency relays. The underfrequency relays are not monitored or supervised by a volts/ hertz element and do not operate or block based on the Volts / hertz. The underfrequency relays typically do have undervoltage blocking which will block underfrequency relay operation for low voltage, but the UFLS relays have no capability to control voltage. Therefore, the ufls relays cannot control voltage level or volts/ hertz and this requirement should be omitted from the UFLS standard characteristics.
Bandera Electric Cooperative	No – Revise the design parameter as noted in the comments	The TRE UFLS SDT feels that, due to the interplay between load and generation components during a firm load shedding event, it would seem impractical to decompose their individual contributions to the volts/Hz ratio; therefore, compliance enforcement would likely prove to be impossible. The TRE UFLS SDT feels that the NERC standard should not specify the relay coordination requirements with generation protection relays. Instead, the NERC standard should state as a requirement for each region to establish as part of the UFLS standard a planning study to determine adequacy and consistency with other standards. For example, the NERC standard might state as follows: "The Regional Standard shall address the requirement for the UFLS to coordinate with existing regional generation relaying requirements." As written, the proposed performance criteria may conflict with ERCOT's Operating Guide 3.1.4.6 where v/Hz is specified.
Louisiana Generqting, LLC	No – Revise the design parameter as noted in the comments	the interplay between the generation control and the load shedding programs will make it difficult to meet this requirement and cumulatively need to be defined.
Orrville Utilities		
Midwest ISO	No – Delete the design parameter	V/Hz design parameters are appropriate for generation protection. We don't believe that is should be considered here as design parameter.
Southern Company Services, Inc	No – Delete the design parameter	A volts per hertz requirement is more appropriate in a generator protection standard.
PJM	No – Delete the design parameter	Add the units after the numbers mentioned (p.u. V/Hz). When discussing cumulatively, when is the accumulation timer reset: after a minute, an hour, a year?
Florida Reliability Coordinating	No – Revise the design parameter as	Replace the words "Bulk Electric System" with "generator terminal". The volts per hertz limits contained in 4.4 correspond to recommendations typical for generators. The temporary overvoltages (TOV) that will follow islanding with UFLS action tend to be significantly higher on the EHV transmission system since generators will

Organization	Question 5	Question 5 Suggested Revisions:
Council	noted in the comments	be absorbing Vars and pulling voltage down. The EHV TOV capabilities are generally much higher than generator V/Hz limits and may be more variable due to individual grid design practices regarding basic insulation level and lightning arrester ratings. Remove of the word “cumulatively”. (See comments for Question No. 3.)The context of the phrase “identified island” requires clarification. (See comments for Question No. 2.)
Southern Company Services, Inc. - Trans	No – Delete the design parameter	This requirement is very difficult to measure. A volts per hertz requirement is more appropriate in a generator protection standard.
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	
We Energies	No – Revise the design parameter as noted in the comments	This design parameter should be revised to clearly indicate that the base value of the per unit frequency component of the Volts per Hz ratio is 60 Hz to avoid any confusion with the scheduled frequencies that are used for time error correction (e.g. 59.98 or 60.02 Hz). In addition, since the values listed in this design parameter are commonly used for generator volts per hertz protection settings, perhaps the system limits should have slightly lower allowable times so the generators do not trip undesirably during this period.
Florida Power & Light Co.	No – Revise the design parameter as noted in the comments	Replace the words Bulk Electric System voltage with generator terminal voltage. The volts per hertz limits contained in 4.4 correspond to recommendations typical for generators. The temporary overvoltages (TOV) that will follow islanding with UFLS action tend to be significantly higher on the EHV transmission system since generators will be absorbing Vars and pulling voltage down. The EHV TOV capabilities are generally much higher than generator V/Hz limits and may be more variable due to individual grid design practices regarding basic insulation level and lightning arrester ratings. The words at least 25% should be replaced with up to 25% for the reasons discussed above.
Exelon		
Progress Energy Carolinas, Inc.	No – Delete the design parameter	This requirement is very difficult to measure from a transmission system perspective. A volts per hertz requirement is more appropriate in a generator protection standard.
Ameren	No – Delete the design parameter	We believe that a volts per hertz requirement is more appropriate in a standard that deals with generation protection issues.
Alliant Energy	No – Delete the design parameter	This a subjective performance criteria as modeling details such as load damping assumptions, inertia assumptions, and governor response assumption will all have considerable effect on performance. This type of performance objective is best evaluated and determined at the Regional level, or some mechanism needs to be in

Organization	Question 5	Question 5 Suggested Revisions:
		place to allow aggressive load shedding programs some latitude on this. There are cases where overshoots above 61 Hz could be accepted for short periods. The type of units in the island also have to be considered. Hydro systems have fewer off-nominal frequency restrictions. The 30 second time limit for operating above 60.5 Hz is not at all appropriate. Units can operate continuously at 60.5 Hz with no accelerated loss of life. They can run slightly above this for a long time. Could this be a typo? Was the intention to establish at 30 minute limit?
E.ON U.S.	No – Revise the design parameter as noted in the comments	See Response to Question 9.
Manitoba Hydro	No – Revise the design parameter as noted in the comments	Again, Manitoba Hydro echo's the MRO's concerns. Each region should determine the volts per Hz based on its system topology, how it was planned and designed and the region's requirements.
PacifiCorp	No – Revise the design parameter as noted in the comments	No issues related to the 1.18 V/Hz proposed requirement. The existing PacifiCorp standard overexcitation trip characteristic follows an inverse time characteristic for values over 1.08 V/Hz. The curve is set to protect a thermal unit per the manufacturer's recommendation. A typical curve will initiate a unit trip if the overexcitation value is 1.10 V/Hz for 291 seconds (4 min 51 seconds) a time delay that is more conservative than the manufacturer's recommendation. Overexcitation values are not typically accumulated. Protective relays implemented to protect the thermal fleet at PacifiCorp to not accumulate Volts/Hertz values. If the overexcitation element starts timing, then drops out, and once again starts timing the initial overexcitation event does not lower the trip time for the second event. ?????
Transmission Reliability Program	No – Revise the design parameter as noted in the comments	Both question #5 above and the third bullet on page 3 of the summary document (starting with Bulk Electric System voltage . . . .) appear to be inconsistent regarding the "time durations" in the standard's characteristics section 4.4. Section 4.4 states: Control Bulk Electric System voltage during and following UFLS operations such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than "two seconds" cumulatively, and does not exceed 1.10 for longer than "45 seconds" cumulatively. The language in question #5 above respectively references 6 seconds cumulatively and 1 minute cumulatively. Based on the discussion on page 3, the shorter timeframes shown in section 4.4 are the correct values.
Independent Electricity System	Yes	

Organization	Question 5	Question 5 Suggested Revisions:
Operator		
CenterPoint Energy	No – Delete the design parameter	As stated previously, CenterPoint Energy believes this effort should be postponed. Alternatively, this proposed design parameter should be deleted until coordination with the PRC-024 drafting team can be firmly established. If the design parameter is not deleted, CenterPoint Energy believes the proposed values are adequate to place proper balance and emphasis on system reliability as system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions.
FirstEnergy Corp.	No – Delete the design parameter	1. When using the term "cumulatively" in this characteristic, when is the accumulation timer reset: a minute, an hour, a year? We are not clear if this is based on a design parameter or an "after-the-fact" performance review. We ask the SDT to provide clarification on this term.2. We recommend that this design parameter be deleted. The intent appears to be an attempt to prevent the overexcitation of generators and, to a lesser degree, transformers. It would be very difficult for entities responsible for setting UFLS equipment to conceive of every imbalance condition and prevent the possibility of any localized generator overexcitation to occur. These design parameters would be more appropriately addressed in generation protection standards to assure that generating units that can have impact on the frequency of the bulk electric system utilize proper overexcitation protection.
American Transmission Company	No – Revise the design parameter as noted in the comments	With respect to the 25 percentage (Characteristic 4), refer to comments for Question 2.With respect to the 6-second or 1-minute V/Hz values (Characteristic 4.4), the basis for these values has not been well established. In addition, for some potential islands the appropriate volt/hertz limits might vary based on the composition of generators and transformers in the island. Absolute continent-wide values may not be appropriate. The Characteristics could require that the proper voltage/hertz limits be investigated and established for each potential island. The proper V/Hz limits should be re-examined and changed, if necessary, whenever a generator or transformer is added or removed for a potential island and may potentially change the limits.
Indiana Municipal Power Agency	No – Revise the design parameter as noted in the comments	The term cumulatively is confusing. It either needs to be clarified or removed. A clarification is needed on the per unit Volts per Hz relay protection. Is this relay protecting a generator step up transformer or a transmission/distribution transformer? If it covers the generator step-up transformer, then this item should not be covered in NERC PRC-024 standard and not in a regional standard.
Duke Energy	No – Delete the design parameter	Delete or at least revise this characteristic. Volts per hertz is not typically monitored or limited on the power system itself. It is more of a concern with regard to equipment protection. This would be a difficult requirement to measure with the current modeling software (and modeling tools). If voltage following an event is the concern, then a requirement for voltage (only) should be stated. The limits in item 4 above should be sufficient to define performance for frequency. It is not clear why a voltage requirement is required since the transmission system must be operated within stated voltage limits regardless. Again, if voltage or issues like tripping capacitors are a concern, it should be stated differently.
Georgia Transmission	No – Delete the design	This requirement would be better served in the generator protection standard.

Organization	Question 5	Question 5 Suggested Revisions:
Corporation	parameter	
Oncor Electric Delivery		
Entergy	No – Delete the design parameter	We agree with and support the SERC comments.
Southwest Power Pool		

6. If there are any other characteristics in the UFLS Regional Reliability Standard Characteristics document that you disagree with, please identify them here, and either identify that they should be deleted, or recommend an alternative.

Organization	Question 6	Question 6 Suggested Revisions:
City Water, Light & Power - Springfield, IL	Agree with all proposed characteristics	
NPCC	Disagree with one or more of the characteristics as noted in the comments	We believe that characteristic 8 in the "UFLS Regional Reliability Standard Characteristics" should require database updates on an annual basis consistent with the requirement for annual certification of the amount of load expected to be shed in characteristic 11. Up-to-date data is a necessary requirement for analysis of system events.
Grand River Dam Authority	Disagree with one or more of the characteristics as noted in the comments	In part 5 and 6 there is reference to PRC-024. I could not find this. Should it be mentioned now or should it wait until it is available?
ERCOT	Disagree with one or more of the characteristics as noted in the comments	Regarding characteristic item 6, we believe it should only apply for Generator(s) that a Region have exempted from being compliant with PRC-024 and hence are aware of the impact on the UFLS effectiveness. The current wording suggests that the UFLS should compensate for any Generator(s) whenever they are non-compliant with PRC-024. Suggested wording be changed to: Item 6. If the Region has exempted any generators from the underfrequency tripping requirements of PRC-024, the Standard shall specify how such generators shall avoid jeopardizing UFLS effectiveness, or how entities responsible for designing UFLS shall compensate for any such non-compliant generators in their area to avoid jeopardizing UFLS effectiveness. The Standard shall require modeling of these method(s) in the UFLS assessment specified in item 10 below to ensure UFLS effectiveness is not jeopardized.
Florida Power & Light		
Manitoba Hydro	Agree with all proposed characteristics	
American Electric Power	Disagree with one or more	

Organization	Question 6	Question 6 Suggested Revisions:
(AEP)	of the characteristics as noted in the comments	
PPL Generation	Disagree with one or more of the characteristics as noted in the comments	Comments on Items 2 and 3: Determination of "potential islands" may be difficult, if not impossible, to determine for tightly integrated electrical systems. Comments on Item 4: As noted earlier, the characteristics proposed should be used as a guideline with provisions for deviation from the guidelines if mis-coordination existing between the UFLS program and legacy generating facilities. Comments on Items 5 and 6: Because PRC-024 is not available for review, it is not clear how these characteristics are related to the standard and how the generator or the entity responsible for the UFLS program is to comply. Comments on Item 9: PPL Corporation suggests identifying a responsible entity very early in the standard drafting process. Failure to do so can make the standard approval process more difficult. Further, identifying the responsible entities early can help in ensuring a better product in the end. Comments on Item 10: PPL Corporation suggests that the Regional Entity be identified as the responsible party. This would be consistent with the SDT's recommendation that the Regional Entity author the standard. If the Regional Entity delegates the responsibility, a separate agreement should be developed to accomplish this rather than rather than including the agreement in the standard. Comments on Item 11: The text of this characteristic is confusing. PPL Corporation suggests clarifying wording of the characteristic and clearly identify what is it be certified annually, i.e. amount (MW) of load to be shed if that is what the SDT intended.
Southwest Power Pool	Disagree with one or more of the characteristics as noted in the comments	If PRC-024 hasn't been developed as an enforceable standard, how do we know that we can comply with Characteristics 5 and 6?
Bandera Electric Cooperative	Disagree with one or more of the	The TRE UFLS SDT believes that the requirement that frequency shall not remain below 59.5 Hz for greater than 30 seconds would require a change in the existing ERCOT UFLS program Step 1 (59.3 Hz). The halfway-point between 60 Hz (normal) and 58.5 Hz (10 second minimum) is 59.25 Hz. Frequency overshoot can be planned for

Organization	Question 6	Question 6 Suggested Revisions:
	characteristics as noted in the comments	by providing numerous steps of UFLS to avoid the overshoot. This should be fine for a gradual decay of frequency. However, during a large drop in frequency, all steps wil operate simultaneously causing a possible overshoot. What can be done to reduce frequency at this point? BEC voltage during and following UFLS operations shall be controlled not to exceed 1.18 for longer than 6 seconds cumulatively and 1.10 for longer than 1 minute cumulatively. Who should be responsible for non-compliance? Can this standard be enforced?
Louisiana Generqting, LLC	Agree with all proposed characteristics	
Orrville Utilities		
Midwest ISO	Disagree with one or more of the characteristics as noted in the comments	Item 5 references standard PRC-024. This standard should be vetted with these characteristics.Item 6 should not use the term non-compliant. A standard and its associated requirements are expected to be complied with. We suggest replacing item 6 with "The standard shall require taking into account the effect of generator underfrequency trip set points."
Southern Company Services, Inc	Disagree with one or more of the characteristics as noted in the comments	Requirement 6 of the characteristics states the following: "The Standard shall specify how generators that are non-compliant with the PRC-024 underfrequency tripping requirement shall avoid jeopardizing UFLS effectiveness, or how entities responsible for designing UFLS shall compensate for any non-compliant generators in their area to avoid jeopardizing UFLS effectiveness. The Standard shall require modeling of these method(s) in the UFLS assessment specified in item 10 below to ensure UFLS effectiveness is not jeopardized." Is this requirement too open-ended for the responsible entity to have to "compensate" for non-compliant generators or does this approach give the responsible entity adequate flexibility to design mitigation plans into its methodologies? This seems to imply that (1) the non-compliant generators have already been identified and (2) that the responsible entity (not the non-compliant generator) shall be held responsible if mitigation plans are insufficient. We feel that Requirement 6 needs to avoid the use of the term "non-compliant" and instead focus on modeling actual generator trip points. We propose replacing Requirement 6 with the following: "The standard shall require taking into account the effect of generator underfrequency trip set points." The requirement, as originally written, is more appropriate in a generator protection standard. Non-compliance with PRC-024 should be addressed within PRC-024.Requirement 5 should be deleted since it is redundant with Requirement 4. Requirement 4.1, 4.2 and 4.3 should be re-worded to establish coordination with PRC-024 in each of the areas shown. As written, we feel there is a possibility of creating a double jeopardy situation with what may be written into the requirements of PRC-024.
PJM	Disagree with one or more	Delete Items 8 and 9 - should be handled in the Functional Model.

Organization	Question 6	Question 6 Suggested Revisions:
	of the characteristics as noted in the comments	
Florida Reliability Coordinating Council	Disagree with one or more of the characteristics as noted in the comments	The characteristics should specify design criteria of the UFLS Programs and should not be confused with the actual system performance following an underfrequency condition. The UFLS Program should be developed to meet the design characteristics with the understanding that system performance will be dependent on the current system conditions and could potentially not meet the design characteristics of the program. Bullet No. 4 of the characteristics should read, "The Standard shall require that the UFLS Program be developed incorporating the following design characteristics?".
Southern Company Services, Inc. - Trans	Disagree with one or more of the characteristics as noted in the comments	In addition to the above comments, requirement #6 need to avoid use of the term "non compliant" and instead focus on modeling actual generator trip points. Propose replacing # 6 with the following: "The standard shall require taking into account the effect of generator underfrequency trip set points." Requirement 5 should be deleted since it is redundant with Requirement 4.
Buckeye Power, Inc.	Agree with all proposed characteristics	
Northeast Utilities	Disagree with one or more of the characteristics as noted in the comments	Section 10.2 of the draft characteristics requires an assessment be conducted every 5 years. Based on experience, the schedule for a given analysis can drag beyond a deadline when there is difficulty in achieving convergence of study results, or modeling problems. There should be some accommodation in the Standard to account for these schedule overruns.
We Energies	Disagree with one or more of the characteristics as noted in the comments	Please see comments associated with question 5.
Florida Power & Light Co.	Disagree with one or more of the characteristics	The design of a coordinated underfrequency load shedding program is primarily a planning activity that is based on analysis of potential islanding scenarios. With the exceptions noted above, it is reasonable to expect that a UFLS program’s technical design parameters will meet the electrical design requirements identified in item four of the UFLS Regional Reliability Standard Characteristics for a load mismatch of 25%. Meeting these frequency and

Organization	Question 6	Question 6 Suggested Revisions:
	as noted in the comments	voltage design limits becomes increasingly difficult with higher load mismatch scenarios. The UFLS Regional Reliability Standard Characteristics as currently drafted implies the performance requirements should be applicable to both planned contingency scenarios and to actual performance during frequency excursions. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of at least 25% will meet the frequency and voltage performance requirements. Applying these requirements to actual disturbance events is inappropriate because of the large number of possible scenarios that may lead to frequency excursions. It is possible that an actual system islanding event occurs through a complex combination of multiple outages and adverse operating conditions that are impossible to predict. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of 25% will meet the frequency and voltage performance requirements. Accordingly, the words or actual system conditions should be removed from item 2 in the UFLS Regional Reliability Standard Characteristics. Item 5 in the UFLS Regional Reliability Standard Characteristics as currently worded would prevent the use of additional layers of backup UFLS protection. The FRCC requires 9 UFLS steps be armed with a total of 56% of planned peak load. Some of these steps provide time delayed backup levels of protection in case frequency stabilizes at a level below 59.7 hertz or in case unplanned generator trips occur. In the event an island formed with a 50% load mismatch, it is likely frequency would go below 57.0 hertz and that generator tripping would occur before these time delayed backup steps would have a chance to operate. The words by requiring that UFLS programs complete execution before generators begin to trip on underfrequency should be removed from item 5 in the UFLS Regional Reliability Standard Characteristics.
Exelon	Disagree with one or more of the characteristics as noted in the comments	Requirement 9 should specify the criteria used to determine an island subject to this standard. Requirements 1 and 2 should specify which entities are responsible for determining what load is responsible for meeting the UFLS performance requirements of R4. Requirement 3 should specify which entities will ensure coordination across intra and inter-Regional boundaries. This should be consistent across the continent. Requirement 5 and 6 should not address specific Standards, as it is unclear how this document could be updated if particular Standards were added, revised, or deleted which affect the Requirements included here. Requirement 6 is confusing - is non-compliance with portions of PRC-024 allowed through mechanisms alluded to here? Requirements 7, 8, 9 and 10 should specify which entities are to maintain a data base, which entities are to maintain the data base and determine required parameters, which entities are responsible for owning, installing, and setting UFLS equipment, and which entities are responsible for performing UFLS assessments, respectively.
Progress Energy Carolinas, Inc.	Disagree with one or more of the characteristics as noted in the comments	In addition to the above comments, NERC Characteristic #6 needs to avoid use of the term "non compliant" and instead focus on modeling actual generator trip points. Propose replacing Characteristic # 6 with the following: "The standard shall require taking into account the effect of generator underfrequency trip set points." Characteristic #5 should be deleted since implementation of Characteristic #4 should achieve this objective (i.e. Characteristic #5 is redundant).

Organization	Question 6	Question 6 Suggested Revisions:
Ameren	Disagree with one or more of the characteristics as noted in the comments	Regarding Item #7, we believe that the Regional Entity should maintain the database to provide uniformity and consistency. Regarding Item #9, the Standard which specifies who owns, install, or sets UFLS equipment should accommodate existing practices. For example, in some organizations, DP actually sheds the load to remedy a GO/TO system-wide event and the standard should ensure that these practices will be allowed to continue. Regarding Item #10, the regional entity should be responsible for performing the assessment or having an assessment performed.
Alliant Energy	Disagree with one or more of the characteristics as noted in the comments	The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. The MRO would ask that characteristics 5 and 6 remove the reference to PRC-024, but do agree with the need for coordination between UFLS and generation protection and expressing the characteristics 5 and 6 in more general terms.
E.ON U.S.	Disagree with one or more of the characteristics as noted in the comments	See Response to Question 9.
Manitoba Hydro	Disagree with one or more of the characteristics as noted in the comments	#8 requires entities to provide data at least every 5 years to support the UFLS database. #11 requires responsible entities to certify annually that the load it expects to shed will result in frequency excursions below the initializing set points of the regional UFLS standard. How can the responsible entity certify this, when the database, and therefore modeled conditions, may be 4 years out of date? Entities should be required to provide data annually to the UFLS, even if it is a "no change" ascertained.
PacifiCorp	Disagree with one or more of the characteristics as noted in the comments	Remove the requirement that the over excitation element be cumulative.
Transmission	Agree with all	

Organization	Question 6	Question 6 Suggested Revisions:
Reliability Program	proposed characteristics	
Independent Electricity System Operator	Agree with all proposed characteristics	
CenterPoint Energy	Disagree with one or more of the characteristics as noted in the comments	Characteristic Item 11 proposes that a UFLS regional standard include a requirement that owners of UFLS equipment must certify, on an annual basis, the amount of load it expects to shed in an underfrequency event. CenterPoint Energy concurs that some type of annual mechanism is warranted to "measure" whether the required load will be shed within a particular region, as UFLS is a critical safety net for the Bulk Power System - providing a last resort function. However, it would be expected that a UFLS regional standard would include the percentages of load to be shed as a Requirement. Therefore, CenterPoint Energy recommends that Characteristic Item 11 be deleted as a Requirement. CenterPoint Energy believes that a Requirement is not the appropriate vehicle to prescribe the type of compliance mechanism (e.g. certification, surveys, assessments), nor the frequency (e.g., annually) of the compliance check. These types of compliance items should be determined through the regional standard development process.
FirstEnergy Corp.	Disagree with one or more of the characteristics as noted in the comments	Characteristics #5 and #6 - It is difficult to determine the acceptability of these characteristics since industry has not yet seen a draft of PRC-024 (Generator Performance During Frequency and Voltage Excursions). Completion of the development of these characteristics and coordination of these characteristics with the proposed requirements of PRC-024 cannot be finalized until the PRC-024 has been fully vetted through industry and approved by NERC and FERC.
American Transmission Company	Disagree with one or more of the characteristics as noted in the comments	The references to the PRC-024 standard should be removed and the desired characteristic restated in more general terms.
Indiana Municipal Power Agency	Disagree with one or more of the characteristics as noted in the comments	A characteristic needs to be added to allow exemptions for equipment that might not be able to meet these under frequency characteristics or the Volts per Hz settings. Some equipment relay protection may not be able to be changed due to OEM limitations which need to be properly protected to prevent equipment damage. If an entity can provide the technical documentation to back up this OEM limitation and notifies the transmission planner, then an exemption should be allowed and not force an entity to be non-compliant.
Duke Energy	Disagree with	Disagreements are noted in the responses above. Additionally, -- Recommend deleting Requirement 5 since it

Organization	Question 6	Question 6 Suggested Revisions:
	one or more of the characteristics as noted in the comments	is redundant with Requirement 4.-- Requirement 6 should avoid use of the term "non compliant". Compliance, and consequently non-compliance, should be handled in PRC-024 itself. If the goal is to verify the UFLS scheme while considering generation trip setpoints, then this requirement should focus on modeling the generation trip setpoints. Propose replacing Requirement 6 with the following: "The standard shall require generator underfrequency tripping be included in the UFLS assessment specified in item 10 below."-- Requirement 2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording should be changed so that islands can be identified as appropriate and not just by system studies or actual system operations. For systems that have not experienced islanding events and where system studies have not shown islands, this would be difficult to meet. Recommend changing the requirement to read, "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS."
Georgia Transmission Corporation	Disagree with one or more of the characteristics as noted in the comments	Requirement #6 needs to avoid the use of the term "non compliant" and instead focus on modeling actual generator trip points
Oncor Electric Delivery		
Entergy	Disagree with one or more of the characteristics as noted in the comments	We agree with and support the SERC comments.
Southwest Power Pool	Disagree with one or more of the characteristics as noted in the comments	Since PRC-024 is not a currently enforceable standard, we can not concur with Characteristics 5 and 6.

7. The SDT proposes that the regional standards include the database requirements contained in existing Reliability Standard PRC-007. Do you agree that database requirements should be addressed within the Regional Standards?

Organization	Question 7	Question 7 Suggested Revisions:
City Water, Light & Power - Springfield, IL	Yes	
NPCC	Yes	
Grand River Dam Authority	Yes	
ERCOT	Yes	
Florida Power & Light	Yes	
Manitoba Hydro		
American Electric Power (AEP)	Yes	
PPL Generation	Yes and No	PPL agrees that the database requirements should be addressed within the Regional Standard developed. However, the data requirements must be clearly identified. Further, the burden of providing such data in particular data formats (for study purposes) should not be delegated to the UFLS program owner - the Regional Entity performing the study should be responsible for data preparation and formatting.
Southwest Power Pool	Yes	
Bandera Electric Cooperative	Yes	The TRE UFLS SDT believes each regional UFLS program should include the requirement for archiving the region's UFLS data and that database should be available to entities within the region and should be part of the region's requirements constituting auditable compliance with the standard. The TRE UFLS SDT feels these databases are required to efficiently conduct the necessary studies. The regional standard should also clearly define the entity responsible/accountable for complying with the standard (equipment ownership, equipment maintenance, database maintenance, reporting, etc.) perhaps the RC or PA. Regardless of who is designated, that functional entity should be responsible for developing a database format/template to ensure UFLS data consistency and completeness as well as study efficiency.
Louisiana	Yes	

Organization	Question 7	Question 7 Suggested Revisions:
Generqting, LLC		
Orrville Utilities		
Midwest ISO	Yes	
Southern Company Services, Inc	Yes	PRC-007 contains the specific requirement for ?documentation [to be provided for the] Regional Reliability Organization to maintain and update a UFLS program database.? PRC-006 specifies the design details to be addressed, such as frequency set points, time delays, etc. Some latitude is given to the regions in formulating the details of their UFLS programs and individual regional programs may differ to some extent. Therefore, in order to demonstrate that these region specific requirements are being meet, the database requirements will need to be included in the regional standards. Also, PRC-006 requires periodic dynamic simulations to assess the effectiveness of the UFLS program (ref. PRC-006 R1.4.2). Since different regions may have different requirements, the ability to obtain the necessary information to perform the required dynamic simulations (either on a regional basis or by individual entities), depends on being able to obtain the type of data that would reside in a UFLS program database. Including the database requirements within the Regional Standards will help ensure this is possible.
PJM	Yes	
Florida Reliability Coordinating Council	Yes	
Southern Company Services, Inc. - Trans	Yes	PRC-007 contains the specific requirement for ?documentation [to be provided for the] Regional Reliability Organization to maintain and update a UFLS program database.? PRC-006 specifies the design details to be addressed, such as frequency setpoints, time delays, etc. Some latitude is given to the regions in formulating the details of their UFLS programs and individual regional programs may differ to some extent. Therefore, in order to demonstrate that these region specific requirements are being meet, the database requirements will need to be included in the regional standards. Also, PRC-006 requires periodic dynamic simulations to assess the effectiveness of the UFLS program (ref. PRC-006 R1.4.2). Since different regions may have different requirements, the ability to obtain the necessary information to perform the required dynamic simulations (either on a regional basis or by individual entities), depends on being able to obtain the type of data that would reside in a UFLS program database. Including the database requirements within the Regional Standards will help ensure this is possible.
Buckeye Power, Inc.	Yes	Regional databases should have a common format and the database should have transparent coordination
Northeast	Yes	

Organization	Question 7	Question 7 Suggested Revisions:
Utilities		
We Energies	Yes	
Florida Power & Light Co.		
Exelon	No	It would be helpful for inter-Regional coordination studies to have a common set of database requirements. Why not specify them here to ensure that this is standardized?
Progress Energy Carolinas, Inc.	Yes	PRC-007 contains the specific requirement for ?documentation [to be provided for the] Regional Reliability Organization to maintain and update a UFLS program database.? PRC-006 specifies the design details to be addressed, such as frequency setpoints, time delays, etc. Some latitude is given to the regions in formulating the details of their UFLS programs and individual regional programs may differ to some extent. Therefore, in order to demonstrate that these region specific requirements are being meet, the database requirements will need to be included in the regional standards. Also, PRC-006 requires periodic dynamic simulations to assess the effectiveness of the UFLS program (ref. PRC-006 R1.4.2). Since different regions may have different requirements, the ability to obtain the necessary information to perform the required dynamic simulations (either on a regional basis or by individual entities), depends on being able to obtain the type of data that would reside in a UFLS program database. Including the database requirements within the Regional Standards will help ensure this is possible.
Ameren	Yes	
Alliant Energy	Yes and No	The MRO agrees that any database requirements should be addressed within the Regional Standards. However, we hope that the database requirements among regions within the same Interconnection are the same. In addition, we would expect that the database would be required to be updated every year.
E.ON U.S.	No	E.ON U.S. believes that database requirements should be established on a case-by-case basis. A database that tracks the dynamically changing system conditions under normal operation is not necessary. Only instances when an UF event occurs should be subject to a data retention requirement
Manitoba Hydro	Yes	
PacifiCorp	Yes	
Transmission Reliability Program	Yes	
Independent Electricity System Operator	Yes	
CenterPoint	Yes	

Organization	Question 7	Question 7 Suggested Revisions:
Energy		
FirstEnergy Corp.	Yes	
American Transmission Company	Yes and No	ATC agrees that any database requirements should be addressed within the Regional Standards. However, we hope that the database requirements among regions within the same Interconnection are the same. In addition, we would expect that the database would be required to be updated every year.
Indiana Municipal Power Agency		
Duke Energy	Yes	
Georgia Transmission Corporation	Yes	
Oncor Electric Delivery		
Entergy	Yes	We agree with and support the SERC comments.
Southwest Power Pool	Yes	

8. Are you aware of any conflicts between the proposed regional standards and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

Organization	Question 8	Question 8 Suggested Revisions:
City Water, Light & Power - Springfield, IL	No	
NPCC	No	
Grand River Dam Authority	No	
ERCOT	No	
Florida Power & Light	No	
Manitoba Hydro	No	
American Electric Power (AEP)	No	All state tariffs need to be reviewed for conflicts.
PPL Generation		
Southwest Power Pool	No	
Bandera Electric Cooperative	Yes and No	The TRE UFLS SDT believes there may potentially be a conflict. The ERCOT Power Region has customer choice of Retail Energy Providers (REP)/LSE. Although the standard appears to be written as permissible in not enforcing UFLS requirements on an LSE ("...and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization)...)", it might be construed that LSEs in ERCOT may be subject to the requirements under the standard as written. The TRE UFLS SDT also comments that the proposed standard does not address allocation to self-serve or large industrials. The TRE UFLS SDT believes that self-serve entities with load and generation connected to the grid should be addressed.
Louisiana Generqting, LLC	No	
Orrville Utilities		

Organization	Question 8	Question 8 Suggested Revisions:
Midwest ISO	No	
Southern Company Services, Inc	Yes	We are concerned that the Under-Frequency Load Shedding characteristics are being developed and finalized prior to the development of the Generator Verification Standard - PRC-024. Since regional standards must coordinate with PRC-024 it is only prudent that the UFLS Drafting Team and the Regions have knowledge of the approved version of PRC-024 before the Drafting Team/Standards Committee requires regions to coordinate with the Generation Verification Standard. Also, some OATT requirements may need to be adjusted to be consistent with regional requirements.
PJM	No	
Florida Reliability Coordinating Council	No	
Southern Company Services, Inc. - Trans	No	Some OATT requirements may need to be adjusted to be consistent with regional requirements.
Buckeye Power, Inc.	No	
Northeast Utilities	No	
We Energies	No	
Florida Power & Light Co.		
Exelon	No	
Progress Energy Carolinas, Inc.	No	Some OATT requirements may need to be adjusted to be consistent with regional requirements.
Ameren	No	
Alliant Energy	No	
E.ON U.S.	No	
Manitoba Hydro	No	
PacifiCorp	Yes and No	Proposed regional standard should specify the responsibility for dropping loads taht are not served by operator of

Organization	Question 8	Question 8 Suggested Revisions:
		the control area, such as power generated in another control area and then scheduled to serve distribution loads of another utility.
Transmission Reliability Program	No	
Independent Electricity System Operator	No	
CenterPoint Energy	No	
FirstEnergy Corp.	Yes	We feel that the design parameters specified in characteristic #4 conflicts with the draft RFC standard and legacy ECAR document.
American Transmission Company	No	
Indiana Municipal Power Agency		
Duke Energy	No	
Georgia Transmission Corporation	No	
Oncor Electric Delivery		
Entergy	No	We agree with and support the SERC comments.
Southwest Power Pool	No	

9. Do you have any other questions or concerns with the proposed Under Frequency Load Shedding Regional Reliability Standard Characteristics that have not been addressed? If yes, please explain.

Organization	**Question 9**	**Question 9 Suggested Revisions:**
City Water, Light & Power - Springfield, IL	No	
NPCC	Yes	We believe that the phrase "meet the following performance characteristics for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent" could be interpreted to require meeting the performance requirements for all generation deficiencies between 25 percent and 100 percent, instead of the intended 0 percent to 25 percent. We recommend that this phrase be revised as "meet the following performance characteristics for underfrequency conditions resulting from all imbalances between load and generation between 0 and 25 percent." We understand the intent of using the words "at least" may have been to recognize that regions may base their program on deficiencies greater than 25 percent; however, it is not necessary to provide within these characteristics that regions may exceed these requirements. The related NERC "Implementation Plan for Underfrequency Load Shedding Regional Reliability Standard Characteristics" must consider that some regional programs may require modification in order to meet these requirements. Accordingly, a time based implementation schedule should be developed with input from the Regional Drafting Teams once more detail surrounding the individual Regional Standards are known.
Grand River Dam Authority	No	
ERCOT	No	
Florida Power & Light	Yes	This proposed standard references PRC -024 which is not yet an approved standard has not been released for comment, and does not seem to be available on the NERC website for review.
Manitoba Hydro	No	
American Electric Power (AEP)	No	
PPL Generation	Yes	PPL agrees with the concept proposed by the SDT. However, unique problems can exist for generators not owned/operated by the host regulated TO/TSP. Such entities cannot make arrangements with "load" to mitigate a generator UF trip setting that may fall above the lowest setting of load UF trip settings. Generator manufacturers UF/OF trip points are extremely important and may be the independent variable in this equation.

Organization	**Question 9**	**Question 9 Suggested Revisions:**
		Generator owners/operators must respect the manufacturer's recommendations for the generator UF trip settings. Generator Owner/Operator shall provide the lowest plant underfrequency setting and basis for this setting to the TO/TSP and or BA/RC in order to ensure coordination with the load UF trip settings. It should also be understood that the lowest manufacturer setting of the generator may not be the driving UF setting that needs to be coordinated with the TO/TSP UFLS scheme of the transmission system. For example, a nuclear unit may have a reactor pump UF setting or the Reactor protective system both having UF relays that can result in a trip of the unit. In any event, the host TO/TOP/TSP/BA needs to coordinate the UFLS program settings with the generators most limiting UF trip settings. The Regional Entity, with input from TO/TSP and generators, should be responsible for ensuring such coordination exists.
Southwest Power Pool	Yes	Please include parameters that will address each region's approach conducting studies as requested in UFLS regional reliability standard characteristic.> Is it acceptable for each region to assume that it is an island separate from neighboring region(s) when performing these studies even though during an actual event each region in Eastern Interconnect is interconnected to neighboring regions?> There is a lot of wording in the questions in the Comment Form that states thing like: "must act", "does not exceed", "must arrest" This type of wording makes very rigid requirements and leaves little room for unplanned situations, mis-operations or acts of God. The wording needs to be modified to include the word "designed"; i.e. the system must be "designed" to act, must be "designed" to not exceed, and must be "designed" to arrest. This seems to apply we are making our best effort to meet the requirement, but not be penalized (found out-of-compliance) for something beyond our control.> The frequency setting of first stage load shedding should be the same across the Eastern Interconnected system.> The frequency set points mentioned in the document such as 58.0, 59.5, 61.0, etc. have been established decades ago by compiling the result of survey from different manufacturers in the IEEE publication. If a common set of frequency setpoints to be adopted for system wide usage, then, it is prudent that these settings be revisited.
Bandera Electric Cooperative	Yes	The TRE UFLS SDT believes the NERC standard should recognize the coordination requirements within and between the region's automatic UFLS and other frequency-related load shed programs. The continent-wide performance criteria should require the regional standard clearly state the authority (i.e., RE, TP, TO, DSP, LSE, etc) that is responsible for the various requirements specified in the standard. The TRE UFLS SDT also questions if the NERC performance criteria should set the values for frequency decline (etc) in the NERC characteristics? Could these be a required characteristic but set by the Region with proof of methodology? Also, what supporting documentation for restricting frequency overshoot to 61.0 Hz? We request that that NERC Generation Verification SDT state its reasoning/explanation. The TRE UFLS SDT also expresses its concern regarding compliance issues. For example, how will compliance be addressed for an entity which meets the region's UFLS program's design standards, yet the program does not yield the results expected under actual conditions? How will compliance be determined?
Louisiana Generqting, LLC	No	

Organization	**Question 9**	**Question 9 Suggested Revisions:**
Orrville Utilities	Yes	This standard should only apply to entities that have the capability of monitoring regional load imbalance. Many distribution providers (DPs) and load serving entities (LSEs) such as municipal utilities and REAs have no knowledge of their regional load status. If these DPs and LSEs are required to own and maintain any type of automated load shedding system, it will be triggered on the basis of frequency. This could possibly cause them to shed load under localized frequency excursions caused by severe weather, which is not required by this standard as written. If load imbalance will remain an integral part of this standard, then entities that do not have the capability to track regional load should be exempt from it. An additional provision of this standard should be to allow DPs and LSEs that draw less than 100 megawatts (perhaps a larger number may be appropriate) from the BES to isolate themselves from the BES before a frequency excursion reaches 59.0 Hz, and/or before the duration of the excursion has reached 30 seconds. Some DPs and LSEs generate a portion of their load, and allowing them to isolate themselves early may enable them to maintain electric service to hospitals, municipal water systems, police and fire departments in the event that the BES cannot be saved from blackout.
Midwest ISO	Yes	Item 10.1 should not require dynamic simulation but rather analytical studies.
Southern Company Services, Inc	Yes	Requirement 2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording needs to be changed because it requires that islands shall be identified through system studies or actual system operations. Some systems may not have experienced any islanding events and system studies may not show any potential events. The wording should be changed so that "other islands deemed appropriate" can be used as the only islands, not just as additional islands. The sentence should read "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." Other areas:1) Requirement 6 (if not replaced as proposed in our response to Question 6) - "The Standard shall specify how generators that are non-compliant with the PRC-024 underfrequency tripping requirement shall avoid jeopardizing UFLS effectiveness, or how [[insert "the entity(s)"]] [[strike "entities"]] responsible for designing UFLS shall compensate?" 2) At Requirements 10.2, 10.3 and 11 an observation was made that the use of "responsible entity" and "entity(s) responsible" seems inconsistent across the three characteristics. If the terminology is consistent, perhaps the drafting team would consider placing Item 11 immediately after Item 9. Both characteristics address "owning, installing, and setting UFLS equipment".3) Requirement 11 - "The Standard shall require that the entity(s) responsible for owning, installing, and setting UFLS equipment, in accordance with item 9 above, shall annually certify [[strike "that"]] the amount of load it expects to shed during a system event which results in system frequency excursions below the initializing set points of the regional UFLS standard."
PJM	No	
Florida Reliability Coordinating	Yes	The design of a coordinated underfrequency load shedding program is primarily a planning activity that is based on analysis of potential islanding scenarios. With the exceptions noted above, it is reasonable to expect that a UFLS program's technical design parameters will meet the electrical design requirements identified in item four of

Organization	**Question 9**	**Question 9 Suggested Revisions:**
Council		the UFLS Regional Reliability Standard Characteristics, for a load mismatch of 25%. Meeting these frequency and voltage design limits becomes increasingly difficult with higher load mismatch scenarios. The UFLS Regional Reliability Standard Characteristics as currently drafted implies the performance requirements should be applicable to both planned contingency scenarios and to actual performance during frequency excursions. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of at least 25% will meet the frequency and voltage performance requirements. Applying these requirements to actual disturbance events is inappropriate because of the large number of possible scenarios that may lead to frequency excursions. It is possible that an actual system islanding event occurs through a complex combination of multiple outages and adverse operating conditions that are impossible to predict. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of at least 25% will meet the frequency and voltage performance requirements. Accordingly, the words "or actual system operations" should be removed from item 2 in the UFLS Regional Reliability Standard Characteristics. Item 5 in the UFLS Regional Reliability Standard Characteristics as currently worded would prevent the use of additional layers of backup UFLS protection. The FRCC requires 9 UFLS steps be armed with a total of 56% of planned peak load. Some of these steps provide backup levels of protection in case unplanned generator trips occur. The words by requiring that UFLS programs complete execution before generators begin to trip on underfrequency should be removed from item 5 in the UFLS Regional Reliability Standard Characteristics. The characteristics, as written, do not allow for a Regional Entity to set the design parameters of a UFLS Program. Since the FRCC has a single UFLS Program, to meet these characteristics the FRCC would be required to write a Regional Standard that would require compliance by the FRCC. The characteristics should be modified to state that these design parameters are required in a Regional Standard, if the Region has UFLS Programs designed by others. They should also state that a Regional Entity may have a UFLS Program and the program should be designed to meet these design parameters.
Southern Company Services, Inc. - Trans	Yes	Requirement 2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording needs to be changed because it requires that islands shall be identified through system studies or actual system operations. Some systems may not have experienced any islanding events and system studies may not show any potential events. The wording should be changed so that "other islands deemed appropriate" can be used as the only islands, not just as additional islands. The sentence should read "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS."
Buckeye Power, Inc.	Yes	It is very important for Major Objective 1 from project 2007-01 to be achieved. If the standard increases costs significantly without providing a demonstrated reliability improvement it will be burdensome for some entities to bear without adding reliability value. A study should be performed to analyze the existing system requirements and to analyze where flexibility can increase or decrease value in the UFLS regional systems as part of the

Organization	**Question 9**	**Question 9 Suggested Revisions:**
		characteristics of the UFLS standard. The study can be used to aid in drafting the regional standard from a quantitative or technical perspective allowing for database coordination.
Northeast Utilities	Yes	Consider whether the document should ensure that responsible parties manage their automatic reclosing programs, along with the UFLS program.
We Energies	No	
Florida Power & Light Co.		
Exelon	No	
Progress Energy Carolinas, Inc.	Yes	Characteristic #2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording needs to be changed because it requires that islands shall be identified through system studies or actual system operations. Some systems may not have experienced any islanding events and system studies may not show any potential events. The wording should be changed so that "other islands deemed appropriate" can be used as the only islands, not just as additional islands. The sentence should read "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS."
Ameren	No	
Alliant Energy	Yes	In general we believe it should be left to the Regions to determine what the UFLS limits should be. As noted in this questionnaire, the SDT found that there are many ways to perform the UFLS function, depending on the characteristics of the Region. We believe that NERC should insure that there is a UFLS program in place in each region, that there is adequate technical justification for each region's UFLS program, the program is reviewed annually and the necessary changes made, etc. The Regions should be responsible to perform the necessary studies, determine the UFLS setpoints, undershoot/overshoot targets, etc. and enforce them. We believe that will deliver the most flexible and efficient method to implement UFLS. Requirement 10.1: Change "through dynamic simulations" to "through analytical studies" because verification of meeting some performance requirements can be performed with other types of methods and simulations. There needs to be an awareness that overvoltages will affect the performance of UFLS load shedding due to the increases in system load. One approach is to trip capacitors along with load (or take comparable actions) to try to keep voltages reasonable. Switchable high voltage line shunts and reactors also need to be considered where appropriate. Obviously, the goal would be to keep voltages close to initial levels as load is shed yet we recognize that despite best efforts, we will get considerable fluctuation in voltage as load is shed.
E.ON U.S.	Yes	The design parameter is dynamic in nature. The Distribution provider at E.ON U.S. installs and maintains the

Organization	**Question 9**	**Question 9 Suggested Revisions:**
		UFLS hardware. E.ON U.S. can not ascertain at this time how the standard will impact the extent and location of individual relays. E.ON U.S. believes that its current installation is adequate to meet this design standard but if NERC believes that they do not, the financial impact of meeting NERC?s requirements could be significant. E.ON U.S. questions whether the expense required to meet the standard, as proposed, is justified given the small likelihood that an UF event will occur. Additionally, the standard is unclear as to how often the process must be updated (annually or other) E.ON U.S. requests that the standard be changed to require updates only when system conditions change to an extent that the existing UFLS processes must be altered. This would protect against doing unneeded updates for standardized time periods but would not eliminate that requirement if system conditions warrant changes in the UFLS processes. Making updates only when necessary as opposed to an administratively determined time frame will reduce costs which will benefit customers
Manitoba Hydro	Yes	Rather than trying to set a uniform performance criteria, the SDT should develop the characteristic and requirements that must be included in the regional and/or subregional UFLS programs and let the regions and subregions to specify the performance criteria to meet the requirements. A key component is to coordinate UFLS with the generator protection for various conditions within the region. Therefore, it should be the responsibility of the regions and/or subregions to design their UFLS for their respective areas.
PacifiCorp	Yes	UFLS Regional Reliability Standard Characteristics should be coordinated and modified if the Generator Verification Standard Drafting Team changes design parameters associated with generating unit protection as well as the generator tripping for both over and under frequency levels.
Transmission Reliability Program	No	
Independent Electricity System Operator	No	
CenterPoint Energy	Yes	This draft contains numerous references to islands, presupposing regional and/or predetermined islanding, which may not be applicable for all interconnections, especially a single region interconnection.
FirstEnergy Corp.	Yes	FE has the following additional comments: 1. We believe that the characteristics should include shedding of load in minimum amount of steps as appropriate for the region. For example, for some regions it is necessary to shed load in a minimum of three steps to prevent overspeed tripping.2. With regard to characteristic #9, it would be difficult for a standard to specify the entity that owns or physically installs UFLS equipment. We suggest this be re-worded as follows: "The standard shall specify the entity(s) responsible for implementing a UFLS program."3. The minimum UFLS characteristics should require coordination between regional entities to assure a wide-area view (i.e. the entire interconnection or wide view based on engineering studies).4. Characteristic #11 requires the regional standard include requirements for the entity to " annually certify the amount of load it plans to shed" We

Organization	**Question 9**	**Question 9 Suggested Revisions:**
		question why the requirement states this since this is more of an audit function; i.e. wouldn't the compliance monitor "certify" this? This characteristic should be removed and believe that the other characteristics cover this.5. We are not clear as to the intent or purpose of Characteristic #1. We recommend that this characteristic be removed since the regional standards will require each entity to set their UFLS equipment that they own and thereby would cover the necessary system boundaries. If there is some other intent to this characteristic, we ask that the SDT explain further and then clarify the wording.
American Transmission Company	Yes	Requirement 10.1: Change "through dynamic simulations" to "through analytical studies" because verification of meeting some performance requirements can be performed with other types of methods and simulations.
Indiana Municipal Power Agency		
Duke Energy	No	
Georgia Transmission Corporation	Yes and No	Each region is different in load to generation mix and transmission configuration. I do not believe that one rule can apply globally to all regions. Only regional stability studies can determine acceptable load shed steps and needs.
Oncor Electric Delivery		
Entergy	Yes	We agree with and support the SERC comments.
Southwest Power Pool	Yes	We would propose that the following statement be included in the UFLS Regional Reliability Standard Characteristics - "Each LSE in a BA footprint is to coordinate their participation in a UFLS program with the host BA."

Consideration of Comments on Underfrequency Load Shedding Characteristics

The Underfrequency Load Shedding Standard Drafting Team thanks all commenters who submitted comments on the UFLS Characteristics document. This document was posted for a 45-day public comment period from July 2, 2008 through August 15, 2008. The stakeholders were asked to provide feedback on the document through a special Electronic Standard Comment Form. There were 38 sets of comments, including comments from more than 100 different people from approximately 100 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Based on stakeholder comments and the drafting team's consideration of those comments, the team has converted the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will refine the proposed standard following the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

The SDT made the following clarifications when converting the UFLS Reliability Standard Characteristics into proposed requirements:

- The responsibility for designing UFLS programs is assigned to groups of Planning Coordinators – each group of Planning Coordinators is expected to work cooperatively with other Planning Coordinators. (R1–R8)
- It is necessary to identify island(s) as a basis for designing the UFLS program, but not necessary to identify every possible island. Analysis to determine islands does not need to predict how island boundaries might form in future events. The SDT modified the criteria for identifying islands. (R3, R4, R5)
- The UFLS system must be designed such that frequency does not drop bellow 58.0 Hz for an imbalance up to and including 25% (rather than "of at least 25%") — for an imbalance exceeding 25%, Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program - the imbalance = (load – actual generation output)/ (load) of up to 25 percent within the identified island – the intent is that this would work for any load level (peak, off-peak, etc.). The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. (R6)
- The cumulative limits apply for each simulated event; not cumulatively for all actual system events. The standard does not require measuring compliance for actual events against the standard. (R6.2)
- Revised the performance characteristics (Requirement R6.2) from 59.5 Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics.
- Revised the performance characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate

with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).

- Modified the performance characteristic in R6.4 to specify where to measure voltages during simulated events.
- Added a requirement (R7.3) in the proposed continent-wide standard to require modeling of automatic load restoration in the five year assessments performed by the group of Planning Coordinators in each region.
- Revised the performance characteristic (Requirement R8) to require annual updates of the database. The SDT also removed the annual certification noting this obligation is effectively addressed by Requirements R9 (annual database updates) and R10 (provide load tripping in accordance with the UFLS program design). The measures by which compliance with these Requirements will be assessed will be defined in the Measures section of the proposed standard.

There were several minority issues that were not resolved when the characteristics were translated into requirements, including the following:

- A preference for a set of Regional Standards in support of continent-wide characteristics, but not a continent-wide standard. The SDT believes that the continent-wide standard will eliminate the confusion caused with the originally proposed requirements that were intended to direct the Regions to create Regional Reliability Standards for UFLS that met the common performance characteristics. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.
- Concern that the performance characteristics may be too specific to accommodate the needs of every region or they may be too extreme for some regions. The SDT feels that the performance characteristics set forth in the proposed continent wide standard are intended to ensure coordination among the programs that Planning Coordinators are required to design.
- Recommendation to revise the performance characteristic from 58.4 Hz to 59.4 Hz for up to nine minutes and continuous above 59.4 Hz. The suggested settings do not coordinate with generator under-frequency time durations allowed by manufacturers.
- Recommendation to specify a minimum size of the postulated island that is of sufficient size to affect the Bulk Electric System and have frequency overshoot requirements for the entire Eastern Interconnection as well as for smaller identified islands. The SDT believes that the UFLS programs must be designed such that all interconnected systems will meet common performance characteristics. Common performance characteristics facilitate coordination between regions. An island could be subject to other performance characteristics in addition to the common performance characteristics for imbalances greater than 25% if the Regional Entities develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.
- Recommendation to establish a common format for the database. The SDT believes that a variety of formats could serve reliability equally well and as such the SDT does not feel compelled to specify a format in the proposed continent-wide standard. The group of Planning Coordinators in each region has been assigned the responsibility for assessments of the UFLS program in the proposed continent-wide standard and is therefore best suited to identify the program database format.

- Recommendation to allow "analytical studies" instead of "dynamic simulations" to verify the UFLS program design. The SDT believes it is not possible to verify the adequacy of the implementation of the regional UFLS program in achieving the performance characteristics without some sort of dynamic simulation and has decided to retain this level of specificity.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
	Individual	Karl Kohlrus	City Water, Light & Power - Springfield, IL	1 - Transmission Owners, 3 - Load-serving Entities, 5 - Electric Generators
	Group	Guy Zito	NPCC	10 - Regional Reliability Organizations/Regional Entities

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Thompson	Consolidated Edison Co. of New York, Inc.	NPCC	1
2.	David Kiguel	Hydro One Networks Inc.	NPCC	1
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Frederick White	Northeast Utilities	NPCC	1
5.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
6.	Ron Falsetti	Independent Electricity System Operator	NPCC	2
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Randy MacDonald	New Brunswick System Operator	NPCC	2
9.	Gregory Campoli	New York Independent System Operator	NPCC	2

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)	
10.	Michael Ranalli		National Grid	NPCC	3
11.	Ronald E. Hart		Dominion Resources, Inc.	NPCC	5
12.	Ralph Rufrano		New York Power Authority	NPCC	5
13.	Brian L. Gooder		Ontario Power Generation Incorporated	NPCC	5
14.	Michael Gildea		Constellation Energy	NPCC	6
15.	Brian D. Evans-Mongeon		Utility Services	NPCC	6
16.	Donald E. Nelson		Massachusetts Dept. of Public Utilities	NPCC	9
17.	Brian Hogue		NPCC	NPCC	10
18.	Alan Adamson		New York State Reliability Council	NPCC	10
19.	Guy Zito		NPCC	NPCC	10
20.	Lee Pedowicz		NPCC	NPCC	10
21.	Gerry Dunbar		NPCC	NPCC	10
	Individual	Edwin Averill	Grand River Dam Authority	5 - Electric Generators, 1 - Transmission Owners, 9 - Federal, State, Provincial Regulatory, or other Government Entities	
	Group	Ken McIntyre	ERCOT	2 - RTOs and ISOs	
	Individual	Don McInnis	Florida Power & Light	1 - Transmission Owners	
	Individual	Vic. Baerg	Manitoba Hydro	1 - Transmission Owners, 5 - Electric Generators, 3 - Load-serving Entities, 9 - Federal, State, Provincial Regulatory, or other Government Entities, 6 - Electricity Brokers, Aggregators	
	Individual	Thad Ness	American Electric Power (AEP)	6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners	

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
	Group	Annette Bannon	PPL Generation	1 - Transmission Owners, 5 - Electric Generators, 6 - Electricity Brokers, Aggregators

Additional Member	Additional Organization	Region	Segment Selection	
1.	Mark Heimbach	PPL EnergyPlus	MRO	6
2.			NPCC	6
3.			RFC	6
4.			SERC	6
5.			SPP	6
6.	John Cummings	PPL EnergyPlus	WECC	6
7.	Joe Kisela	PPL Generation	RFC	5
8.			NPCC	5
9.	Tom Lehman	PPL Montana	WECC	5
10.	Dave Gladey	PPL Susquehanna	RFC	5
11.	Mike DeCesaris	PPL Electric Utilities	RFC	1
12.	Gabe Laczo	PPL Electric Utilities	RFC	1
13.	Gary Bast	PPL Electric Utilities	RFC	1
14.	Dave Price	PPL Electric Utilities	RFC	1

	Group	Lynn Schroeder	Southwest Power Pool (SPP UFLS Standard Drafting Team)	10 - Regional Reliability Organizations/Regional Entities
	Group	Brian Bartos	Bandera Electric Cooperative (TRE Regional UFLS Standard Drafting Team)	1 - Transmission Owners

Additional Member	Additional Organization	Region	Segment Selection	
1.	Dennis Kunkel	AEP	ERCOT	1
2.	Randy Jones	Calpine	ERCOT	5
3.	Matt Pawlowski	FPL Energy	ERCOT	5

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
4.		Rayborn Reader	EPCO	ERCOT 7
5.		Eddy Reece	Rayburn Country	ERCOT 1
6.		Barry Kremling	GVEC	ERCOT 1
7.		Sergio Garza	LCRA	ERCOT 1
8.		Steve Myers	ERCOT ISO	ERCOT 2
9.		Ken McIntryre	ERCOT ISO	ERCOT 2
	Individual	O. J. Brouillette	Louisiana Generating, LLC	3 - Load-serving Entities, 5 - Electric Generators, 4 - Transmission-dependent Utilities, 1 - Transmission Owners
	Individual	Steve Harmath	Orrville Utilities	4 - Transmission-dependent Utilities
	Group	Marie Knox	Midwest ISO	2 - RTOs and ISOs

Additional Member	Additional Organization	Region	Segment Selection
1.	Kirit Shah	Ameren	SERC 1
2.	Jim Cyrulewski	JDRJC Associates	RFC 8

	Group	Jim Busbin	Southern Company Services, Inc	5 - Electric Generators, 1 - Transmission Owners

Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Wilson	Southern Company Services	SERC 1
2.	Terry Coggins	Southern Company Services	SERC 1
3.	Jonathan Glidewell	Southern Company Services	SERC 1
4.	Raymond Vice	Southern Company Services	SERC 1
5.	J. T. Wood	Southern Company Services	SERC 1
6.	Terry Crawley	Southern Company Services	SERC 5
7.	Marc Butts	Southern Company Services	SERC 1

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
	Individual	Mark Kuras	PJM	2 - RTOs and ISOs
	Group	Peter Heidrich	Florida Reliability Coordinating Council	1 - Transmission Owners, 4 - Transmission-dependent Utilities, 3 - Load-serving Entities, 10 - Regional Reliability Organizations/Regional Entities, 5 - Electric Generators

Additional Member	Additional Organization	Region	Segment Selection	
1.	Jerry Murphy	Reedy Creek Improvement District	FRCC	3
2.	John Shaffer	Florida Power & Light	FRCC	1
3.	John Odom	FRCC	FRCC	10
4.	Fabio Rodriguez	Progress Energy	FRCC	1
5.	Don GIlbert	JEA	FRCC	5
6.	Alan Gale	City of Tallahassee	FRCC	5
7.	Don McInnis	Florida Power & Light	FRCC	1
8.	Art Nordlinger	Tampa Electric Company	FRCC	1
9.	FRCC System Protection & Control Subcommittee	FRCC	FRCC	10

	Group	Bob Jones	Southern Company Services, Inc. - Trans	1 - Transmission Owners

Additional Member	Additional Organization	Region	Segment Selection	
1.	Rick Foster	Ameren	SERC	1
2.	Anthony Williams	Duke Energy Carolinas	SERC	1
3.	Greg Davis	Georgia Transmission Corp.	SERC	1
4.	Ernesto Paon	Municipal Electric Authority of Georgia	SERC	1
5.	Andrew Fusco	NC Municipal Power Agency #1	SERC	1
6.	John O'Connor	Progress Energy Carolinas	SERC	1
7.	Pat Huntley	SERC Reliability Corp.	SERC	10
8.	Jonathan Glidewell	Southern Company Services, Inc. - Trans	SERC	1

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
9.		Tom Cain	Tennessee Valley Authority	SERC 1
	Individual	Kevin Koloini	Buckeye Power, Inc.	3 - Load-serving Entities, 4 - Transmission-dependent Utilities, 5 - Electric Generators
	Individual	Rick White	Northeast Utilities	1 - Transmission Owners
	Individual	Howard Rulf	We Energies	5 - Electric Generators, 4 - Transmission-dependent Utilities, 3 - Load-serving Entities
	Individual	John W Shaffer	Florida Power & Light Co.	1 - Transmission Owners
	Individual	Eric Mortenson	Exelon	1 - Transmission Owners, 3 - Load-serving Entities
	Individual	D. Bryan Guy	Progress Energy Carolinas, Inc.	3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners
	Individual	Kirit Shah	Ameren	6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 1 - Transmission Owners
	Group	Ken Goldsmith (MRO NERC Standards Review Subcommittee)	Alliant Energy	4 - Transmission-dependent Utilities

Additional Member	Additional Organization	Region	Segment Selection	
1.	Neal Balu	WPS	MRO	3, 4, 5, 6
2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Jim Haigh	WAPA	MRO	1, 6
5.	Tom Mielnik	MEC	MRO	1, 3, 5, 6
6.	Pam Sordet	Xcel	MRO	1, 3, 5, 6
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Eric Ruskamp	LES	MRO	1, 3, 5, 6

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)
9.		Joseph Knight	GRE	MRO	1, 3, 5, 6
10.		Joe DePoorter	MGE	MRO	3, 4, 5, 6
11.		Larry Brusseau	MRO	MRO	10
12.		Michael Brytowski	MRO	MRO	10
	Group	Brent Ingebrigtson	E.ON U.S.	6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners
	Individual	Kris Manchur	Manitoba Hydro	5 - Electric Generators, 6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 1 - Transmission Owners
	Group	Sandra Shaffer	PacifiCorp	1 - Transmission Owners, 5 - Electric Generators, 3 - Load-serving Entities

Additional Member	Additional Organization	Region	Segment Selection	
1.	Mike Viles	Transmission Technical Operations	WECC	1
2.	Kelly Johnson	Transmission Customer Service Engineering	WECC	1
3.	Terry Doern	Transmission Technical Operations	WECC	1
4.	Gregory Vasallo	Transmission Customer Service Engineering	WECC	1
5.	Stephen Hitchens	Transmission Technical Operations	WECC	1
6.	Rebecca Berdahl	Power Long Term Sales and Purchases	WECC	3

	Group	Denise Koehn	Transmission Reliability Program	3 - Load-serving Entities, 5 - Electric Generators, 1 - Transmission Owners, 6 - Electricity Brokers, Aggregators
	Individual	Ron Falsetti	Independent Electricity System Operator	2 - RTOs and ISOs
	Individual	Wayne Kemper	CenterPoint Energy	1 - Transmission Owners
	Group	Sam Ciccone	FirstEnergy Corp.	1 - Transmission Owners, 5 - Electric Generators, 3 - Load-serving Entities, 6 - Electricity Brokers, Aggregators

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)

Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FirstEnergy	RFC	1, 3, 5, 6
2.	Dave Folk	FirstEnergy	RFC	1, 3, 5, 6
3.	Art Buanno	FirstEnergy	RFC	1
4.	Jim Detweiler	FirstEnergy	RFC	1
5.	Bob McFeaters	FirstEnergy	RFC	1
6.	Ken Dresner	FirstEnergy	RFC	5
7.	Bill Duge	FirstEnergy	RFC	5

	Group	Jason Shaver	American Transmission Company	1 - Transmission Owners
	Individual	Scott Berry	Indiana Municipal Power Agency	4 - Transmission-dependent Utilities
	Individual	Greg Rowland	Duke Energy	5 - Electric Generators, 6 - Electricity Brokers, Aggregators , 3 - Load-serving Entities, 1 - Transmission Owners
	Group	Greg Davis	Georgia Transmission Corporation	1 - Transmission Owners
	Individual	Greg Ward / Darryl Curtis	Oncor Electric Delivery	1 - Transmission Owners
	Individual	Ed Davis	Entergy	
	Group	Robert Rhodes	Southwest Power Pool	1 - Transmission Owners, 2 - RTOs and ISOs, 3 - Load-serving Entities, 4 - Transmission-dependent Utilities, 5 - Electric Generators

Additional Member	Additional Organization	Region	Segment Selection	
1.	Bill Bateman	East Texas Electric Coop.	SPP	3, 4
2.	John Boshears	City Utilities of Springfield	SPP	1, 3, 5
3.	Brian Berkstresser	Empire District Electric	SPP	1, 3, 5

	Individual or group.	Name	Organization	Registered Ballot body segment (check all industry segments in which your company is registered)	
4.		Mike Gammon	Kansas City Power & Light	SPP	1, 3, 5
5.		Don Hargrove	Oklahoma Gas & Electric	SPP	1, 3, 5
6.		Danny McDaniel	CLECO	SPP	1, 3, 5
7.		Kyle McMenamin	Southwestern Public Service Company	SPP	1, 3, 5
8.		Eddy Reece	Rayburn Country Electric Coop	SPP	3, 4
9.		Robert Rhodes	Southwest Power Pool	SPP	2

1. The SDT determined that there is no need to have a continent-wide standard, and proposes that all UFLS requirements be contained within the regional UFLS standards developed in accordance with the Characteristics of UFLS Regional Reliability Standards. The SDT developed a set of characteristics which each of the regional entities will be directed to include in its UFLS regional reliability standard. The SDT developed these characteristics in an attempt to direct the regional entities to develop requirements based on system performance, without prescribing specifics of how to meet the specified performance. Do you agree with the drafting team?

Summary Consideration:

The Underfrequency Load Shedding Drafting team reviewed comments for this question and has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a proposed continent wide standard that will follow the standards development process. The team acknowledges that this is a shift in approach but sees many benefits to proceeding with a continent-wide standard.

1. While the majority of the comments indicated support for the creation of Regional Standards that determine the details of the UFLS programs the majority of the comments also generally supported the concept of applying common continent-wide characteristics. The Regional Standards would have to meet these common performance characteristics. The creation of a continent-wide standard does not deviate from this approach but rather eliminates the confusion caused with this new form of requirement that was intended to direct the Regions to create Regional Reliability Standards for UFLS that met the common performance characteristics.
2. The creation of a continent-wide standard does not prohibit the creation of Regional Standards for UFLS. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. This approach still allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
3. Several commenters expressed concern that the approach set forth in the first posting (the directive to the Regions containing the performance characteristics) was "a new kind of requirement listing [that] circumvents the Standard Development Procedure". Further, commenters expressed concern that this approach creates a "new class of Standards [that] creates confusion" namely that is unclear how the characteristics would be revised in the future and the role stakeholders would play in future revisions. The SDT agrees with these comments and feels that by creating a continent wide standard containing the performance characteristics these concerns will be addressed leaving the more detailed requirements (if needed) to a Regional Standard or Regional Variance as outlined in the NERC Rules of Procedure.
4. Several commenters indicated that they thought it appropriate that the Regions develop the details of the UFLS program such as the total amount to load shed; how many blocks at what frequency, etc. The SDT clarifies that the performance characteristics are intended to ensure coordination among the programs. In the proposed continent-wide standard the SDT assigned the responsibility of designing the UFLS program to the Planning Coordinator (Requirement R2). The Planning Coordinators within a region will define the amount of load shed required, how many blocks, at what frequency, etc. (these specific requirements are not contained in the proposed continent wide standard).
5. Several commenters indicated that the performance characteristics may be too specific to accommodate the needs of every region or they may be too extreme for some regions. The SDT feels that the performance characteristics set forth in the proposed continent wide standard are intended to ensure coordination among the programs that Planning Coordinators are required to design. For an imbalance up to and

including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

6. Several commenters asked the SDT to clarify if their intent is to withdraw PRC-006-0, PRC-007-0 and PRC-009-0 when applicable regional replacement standards are established and become effective. In addition, the commenters interpreted that the SDT directive approach was a means for NERC to require the Regions to develop appropriate Regional standards that share continent-wide characteristics because NERC standards cannot be applied to Regional Entities. The SDT recognizes that NERC standards should not be applicable to Regional Entities and confirms that this was the original intent of the "UFLS Regional Reliability Standard Characteristics"; however, the SDT decided to convert the directive into a continent wide standard as a means for NERC to require shared continent wide characteristics applicable to Planning Coordinators, Transmission Owners, and Distribution Providers. The proposed continent wide standard would replace PRC-006-0, PRC-007-0, and PRC-009-0 once it is approved and becomes effective.

Organization	Question 1:	Question 1 Comments:
PJM	No	UFLS should be used as a safety net, based on installation requirements rather than performance requirements. As it is currently worded, if your UFLS load shedding does not arrest a blackout, you could potentially be found non-compliant.
Response: The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6).		
Exelon	No	This document, 'Characteristics of UFLS Regional Reliability Standards' is not a NERC Standard, yet it contains requirements for adherence by parties other than NERC or a Region. This new kind of requirement listing circumvents the Standard Development Procedure. It is not clear how this could ever be revised or what role stakeholders have in this. The creation of a new class of Standards creates confusion and is contrary to the well developed process that has been established. Why couldn't this be a NERC Standard, with all of the recognized checks and balances provided with that process, while at the same time leaving the few requirements that really need to be 'fill in the blank' up to a more detailed Regional Standard?
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
Oncor Electric Delivery	No	Oncor Electric Delivery does not believe that this document should be issued at this time. Many of the proposed design characteristics are based on parameters contained in the proposed NERC Reliability Standard PRC-024 which is still in the development stage. This document should be reissued for comments once PRC-024 has been approved.
Response: The SDT agrees that performance characteristics should be based on the proposed generator under-frequency time durations in PRC-024. In addition, the SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team (GV SDT)by providing the underfrequency performance curve to ensure that		

Organization	Question 1:	Question 1 Comments:
the performance characteristics do not conflict with the generator off nominal frequency capability curve. The SDT will continue to coordinate with the GV SDT and we believe it does not matter whether PRC-006 or PRC-024 is approved first as long as this coordination exists.		
Southwest Power Pool	No	We have concerns that in eliminating the continent-wide standard we are also eliminating continent-wide enforcement and the common denominator that NERC provides through the reliability standards. Under the proposal, enforcement would apparently fall to each regional entity which could lead to inconsistency across an interconnection.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
CenterPoint Energy	No	CenterPoint Energy believes this document has been issued for comments prematurely and recommends this effort be postponed until the proposed NERC Reliability Standard PRC-024 (Generator Protective System Performance During Frequency and Voltage Excursions) has been fully developed and vetted by all stakeholders through the NERC process. The prescriptive technical design characteristics proposed in these Characteristics of UFLS Regional Reliability Standards are based on parameters contained in the proposed PRC-024 that have not yet been issued to the industry for comments. It is premature to base these Characteristics on another standard that is still in the development process. **Response:** The SDT agrees that performance characteristics should be based on the proposed generator under-frequency time durations in PRC-024. In addition, the SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team (GV SDT) by providing the underfrequency performance curve to ensure that the performance characteristics do not conflict with the generator off nominal frequency capability curve. The SDT will continue to coordinate with the GV SDT and we believe it does not matter whether PRC-006 or PRC-024 is approved first as long as this coordination exists. As an alternative to postponing this effort, the proposed prescriptive technical characteristics could be deleted. While CenterPoint Energy proposes less restrictive characteristics in response to Questions 2, 3, and 4 below, our recommendation is that they be deleted or that Project 2007-1 be postponed. All the proposed technical design parameters appear to apply only for "underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent". This characterization is simplistic and does not address all UFLS needs for other system conditions that can occur. The imbalance and response to an imbalance can vary dramatically considering not only the amount of generation that's on-line, but also the type of generation on-line. System response will depend upon governor response and system inertia. For example, in order to arrest frequency decay for a 25% load / generation imbalance within prescribed parameters under certain conditions, a region may have to employ aggressive load shedding that might cause an overshoot beyond prescribed parameters under other conditions. This is especially true for regions that have significant penetration of wind energy, where system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions. The open ended requirement for arresting frequency after an initial imbalance of at least 25% could be interpreted to encompass imbalances of 50%, 75% or even

Organization	Question 1:	Question 1 Comments:
		100% which is infeasible. **Response:** The SDT agrees that the system off nominal frequency performance is a function of many factors and that simulation modeling assumptions can vary widely. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. Compliance with performance characteristics when the imbalance is greater than 25 % is not required by this standard. The SDT believes that proposed performance characteristics values are achievable for generator deficits up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.
PPL Generation	Yes and No	PPL Corporation agrees with the SDT that a continent-wide standard is not practical and having the regional entities develop a process and appropriate requirements consistent with the "Characteristics of UFLS Regional Reliability Standards" is the most effective way to ensure a reliable transmission system. We also agree it is necessary for the standard to establish specific limits. However, rigid adherence to the stated characteristics may not be possible for certain generating facilities because of equipment limitations or manufacturer recommended over/under frequency protection requirements. Such limitations or requirements can not be ignored. As such, provisions to deviate from stated characteristics in these instances must be included in any regional entity standard developed. The expectation is that the generator would provide documentation as to why a specific characteristic can not be met and the regional entity would review the issue and determine if mis-coordination with the UFLS program exists. If mis-coordination does exist, the regional entity, with input from the host TO/TSP and the generator, would then be responsible for appropriate mitigation measures (i.e. shedding of additional load).
Response: The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: “To ensure that generators will not trip off-line during specified voltage and frequency excursions.” The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.		
Ameren	Yes and No	We agree that there is no need for a continent-wide UFLS standard. However, numerous system conditions would need to be studied to identify potential islands (Characteristic #2), and we doubt that the analyses to be performed would often accurately predict how the system would separate with any certainty. Also, it is likely that any separation would not be along company or regional lines. Therefore, we suggest that each region involve and coordinate neighboring regions in these studies and in the development of the regional UFLS standard and its requirements.
Response: The SDT agrees that analysis to determine islands would not necessarily predict how island boundaries would form in real events. However, it is necessary to identify island(s) as a basis for designing the UFLS program (Requirement R5). Assessment of islands that overlap regional boundaries requires coordination between adjacent regions. The intent of characteristic 3 (Requirement R4) is to ensure		

Organization	Question 1:	Question 1 Comments:
that Planning Coordinators have procedures in place to carry out required coordination.		
Midwest ISO	Yes and No	We agree with the drafting team's approach in developing a set of system characteristics rather than a continent wide standard. We are concerned though that when standards PRC-006, PRC-007, and PRC-009 are replaced that information and requirements could be lost that are important to UFLS. Regional standards drafting teams should review the content of these existing standards to determine what should be transferred to their standards. We believe that the characteristics are a good starting point and should set a minimum level of performance expected. The drafting team should consider whether there are any special systems (such as a peninsula) that may warrant different criteria and allow the regional standards to consider other criteria for those systems. To better assess the quality of the characteristics, the drafting team should provide the history behind these characteristics. Where did they come from? How were they derived? Did they come from old regional reliability organization (from MAIN, MAPP, ECAR, etc) criteria?
Response: The SDT team developed a mapping document (included in the Implementation Plan) to ensure that requirements would not be lost. This may address the concerns regarding losing requirements in the merging of the three standards. The SDT notes that the requirements that were not included in the proposed characteristics are currently included in the NERC ERO Rules of Procedure (Appendix 8 – NERC Blackout and Disturbance Response Procedures). If the commenter feels (after reviewing the mapping) that the SDT has left out requirements please inform the SDT. The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. Regarding the history for the performance characteristics, the technical basis for the performance characteristics was developed through a review of relevant industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. The SDT included more details regarding the technical justification for the performance characteristics in the comment form background (including specific IEEE standards). In addition, the SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team by providing the underfrequency performance curve to ensure that the performance characteristics do not conflict with the generator off nominal frequency capability curve.		
Alliant Energy	Yes and No	The MRO believes that the Regions should determine the details of the UFLS. We believe the regions are best situated to perform the studies and determine the total amount of load shed required, how many blocks, at what frequency, etc. This includes setting regional performance objectives for UFLS design, and deciding on generator under/over frequency minimum time delays and frequency setpoints. **Response:** The SDT has decided to convert the “Characteristics of UFLS Regional Reliability Standards” into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. The Planning Coordinators within a region will define the amount of load shed required, how many

Organization	Question 1:	Question 1 Comments:
		blocks, at what frequency, etc. Generator under/over frequency minimum time delays and frequency setpoints are covered under PRC-024 Generator Verification. The MRO believes that the Under Frequency Load Shedding Standard Drafting Team is headed in the right direction as far as allowing the regions to create their own UFLS program within continental wide characteristics. It's the MRO's contention that while the 11 general characteristics are reasonable they may be too specific to accommodate the needs of every region or they may be too extreme for every region. The MRO asks that the UFLS SDT allow the regions a reasonable amount of time to determine the specific number which would accommodate the general NERC objectives but would address regional conditions. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. There are some inconsistencies in the document as the Characteristics listed in the "UFLS Regional Reliability Standard Characteristics" document do not match with those listed in this comment form in the "Characteristics of UFLS Regional Reliability Standards" section. Specifically, 1) What is the technical justification for the frequency overshoot limit of 61 Hz? (third bullet) 2) What is the technical justification for the time durations for the Volts/Hz? (Fourth Bullet) **Response:** Performance characteristic 4.4 (Requirement R6.4) states that: Control voltage during and following UFLS operations such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than two seconds cumulatively per simulated event, and does not exceed 1.10 for longer than 45 seconds cumulatively per simulated event. The comment form does not reflect the characteristic but should have. This was an oversight. Regarding the justification for the Volts/Hz performance characteristic, the technical basis for this performance characteristic was developed through a review of relevant industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. The SDT included more details regarding the technical justification for the performance characteristics in the comment form background (including specific IEEE standards). The MRO interprets that the STD is proposing the withdrawal of the PRC-006-0, PRC-007-0, and PRC-009-0 standards when applicable Regional replacement standard(s) are established and become effective. The MRO also interprets that the STD is proposing UFLS Regional Reliability Standard Characteristics, rather than revising the NERC UFLS

Organization	Question 1:	Question 1 Comments:
		standards, because NERC standards cannot be applicable to Regional Entities and the Characterizes may be a means for NERC to require the Regions to develop appropriate Regional standards that share key continent-wide characteristics. **Response:** The SDT recognizes that NERC standards should not be applicable to Regional Entities and confirms that this was the original intent of the "UFLS Regional Reliability Standard Characteristics"; however, the SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard as a means for NERC to require shared continent-wide characteristics. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The MRO agrees that the existing NERC standards could be replaced with appropriate Regional standards and believe that some UFLS program requirements should be different in different Regions. The MRO disagrees that the Characteristics should direct Regional Entities to be based on continent-wide system performance values. Appropriate system performance levels and appropriate percentage of load shedding will vary for each potential island and depend on the composition of load, generation, and system protection within the island. The continent-wide Characteristics should deal with such broader issues such as: identification of potential islands, coordination among accountable entities, identification of appropriate load shedding percentage, identification and coordination with island-specific generation-related limits and system protection settings, responsibility for UFLS program design and implementation, responsibility for and frequency of UFLS program assessment, etc. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. The Planning Coordinators within a region will define the amount of load shed required, how many blocks, at what frequency, etc. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.
FirstEnergy Corp.	Yes and No	We agree with the SDT that there is no need for NERC to develop a continent-wide standard since there is already much work being done in some regions already creating their own regional standard. And we agree that NERC should at least specify the minimum expectations of UFLS programs needed by each region so that there is continent-wide consistency in the creation and implementation of regional UFLS standards. However, it is not clear how this document will be maintained in the NERC reliability standards realm. This document does not appear to have a standard number and version so that it can be maintained and used as a living document to be used as a reference for the minimum regional requirements. We are concerned that after these minimum regional characteristics are vetted through industry and subsequently used by the regions to create their initial versions of their region's UFLS standard, they will not be transparent to the regions years from now when they revise their standards. Additionally, at some point NERC and industry may determine the need to add and/or revise these minimum regional characteristics due to ever changing

Organization	Question 1:	Question 1 Comments:
		industry technology or methodologies regarding UFLS equipment design and utilization.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
American Transmission Company	Yes and No	ATC interprets that the STD is proposing the withdrawal of the PRC-006-0, PRC-007-0, and PRC-009-0 standards when applicable Regional replacement standard(s) are established and become effective. ATC also interprets that the STD is proposing UFLS Regional Reliability Standard Characteristics, rather than revising the NERC UFLS standards, because NERC standards can not be applied to Regional Entities and the Characteristics may be a means for NERC to require the Regions to develop appropriate Regional standards that share key continent-wide characteristics. **Response:** The SDT recognizes that NERC standards should not be applicable to Regional Entities and confirms that this was the original intent of the "UFLS Regional Reliability Standard Characteristics"; however, the SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard as a means for NERC to require shared continent-wide characteristics. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. We agree that the existing NERC standards could be replaced with appropriate Regional standards and believe that some UFLS program requirements should to be different in different Regions. ATC disagrees that the Characteristics should direct Regional Entities to be based on continent-wide system performance values. Appropriate system performance values and appropriate percentage of load shedding will vary for each potential island and depend on the nature of load, generators, protection schemes, and dispatch within each island. The continent-wide Characteristics should deal with such broader issues such as: identification of potential islands, coordination among accountable entities, identification of appropriate load shedding percentage, identification and coordination with island-specific generation-related limits and system protection settings, responsibility for UFLS program design and implementation, , responsibility for and frequency of UFLS program assessment, the factors to be considered in assessments, etc. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. The Planning Coordinators within a region will define the amount of load shed required, how many blocks, at what frequency, etc. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

Organization	Question 1:	Question 1 Comments:
City Water, Light & Power - Springfield, IL	Yes	In the Eastern Interconnection, it's probably good that not all regions shed load and the same frequencies. Doing so could lead to unstable conditions when the grid is already stressed.
Response: The SDT disagrees that having all regions shed load at the same frequency could lead to an unstable condition, however, the SDT confirms that it is not necessary for all regions to shed load at the same frequencies.		
Manitoba Hydro	Yes and No	Manitoba Hydro agrees that region must have the flexibility to institute a UFLS that meets its region's topology requirements. Manitoba Hydro also agrees that the SDT should develop requirements based on system performance. However, the performance targets outlined in the characteristics document are not all appropriate for every region (specifics described in following comments).
Response: Please see our responses to your comments on the following questions.		
Entergy	Yes and No	In general, we agree with the specifics prescribed by the drafting team and believe it is in the best interest of reliability to develop specific operating characteristics for each region. However, we do not agree with the design parameters set in section 4.
Response: Please see our responses to your comments on Questions 3 and 4.		
Southwest Power Pool	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not necessarily include those specific characteristics as requirements in the Regional Standard.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
Bandera Electric Cooperative	Yes	The Texas Regional Entity Regional Underfrequency Standard Drafting Team (TRE UFLS SDT) agrees with the direction that the NERC team is proposing. Performance outcomes should be the focus of the regional standards development to allow for the proper integration of practices that have long been based on regional differences and practices. Those practices, where they obviously lend themselves to achieving the expected reliability outcomes, should be respected and incorporated in the development of these new regional standards.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		

Organization	Question 1:	Question 1 Comments:
Southern Company Services, Inc	Yes	This approach allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
SERC	Yes	This approach allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
Progress Energy Carolinas, Inc.	Yes	This approach allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
Independent Electricity System Operator	Yes	We support this approach
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
Georgia Transmission Corporation	Yes	This will allow each region to develop standards that meet the specific needs of their region
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
NPCC	Yes	
Grand River Dam Authority	Yes	
ERCOT	Yes	
Florida Power & Light	Yes	

Organization	Question 1:	Question 1 Comments:
American Electric Power (AEP)	Yes	
Louisiana Generqting, LLC	Yes	
Orrville Utilities	Yes	
Florida Reliability Coordinating Council	Yes	
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	
We Energies	Yes	
E.ON U.S.	Yes	
PacifiCorp	Yes	
Transmission Reliability Program	Yes	
Duke Energy	Yes	
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and will follow the standards development process. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		

2. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must arrest frequency decline at no less than 58.0 Hz. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Summary Consideration:

The SDT reviewed the comments received and made several conforming changes to the performance characteristics (now requirements) and/or provided the commenter with a response explaining the team's intent.

- Several commenters requested that the SDT clarify if the intent of this performance characteristic is to ensure an entity's UFLS scheme operates in its entirety prior to 58.0 Hz or that the system frequency must never drop below 58 Hz. The SDT clarified that the intent of the characteristic is that the system must be designed such that frequency does not drop bellow 58.0 Hz for an imbalance up to and including 25%.

- Many commenters indicated in their comments that the terms used in the performance characteristic "imbalance between load and generation" and "at least 25 percent" should be modified or clarified. In response to these comments, the SDT modified the performance characteristic (now Requirement R6) to clarify that an imbalance = (load – actual generation output)/ (load) of up to 25 percent within the identified island. Compliance with the performance characteristics when the imbalance is greater than 25% is not required by this standard. The SDT believes that the proposed characteristics values are achievable for generator deficits up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

- Some commenters indicated that the 25% stated in the characteristic should represent that amount of load at system peak that could be shed by UFLS relays. The SDT clarified that the 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The intent is that this would work for any load level (peak, off-peak, etc.).

- Several of the comments received indicated that UFLS should be used as a safety net based on installation requirement rather than performance requirements. Further, as worded the performance characteristic is almost impossible to meet unless all load is on UFLS. The SDT clarified that the design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6).

- Several comments indicated that the phrase "identified island" requires clarification. Is it required that the entity identify any island that has the possibility of being formed as a result of a system disturbance? And if so, it is not appropriate for these characteristics to require every possible island to meet the load mismatch criteria. The SDT clarified that it is not the intent to identify every possible island or perform an exhaustive analysis. However, it is necessary to identify island(s) as a basis for designing the UFLS program (Requirement R5). The SDT clarified requirements concerning identification of islands in Requirements R3, R4, and R5. The SDT believes that analysis to determine islands does not need to predict how island boundaries might form in future events.

Organization	Question 2	Question 2 Comments:
American Electric Power (AEP)	No Revise the design parameter as noted in the comments	The statement "the UFLS must arrest frequency decline at no less than 58.0 Hz" needs to be clarified. Is the intent of this characteristic to ensure an entity's UFLS scheme operates in its entirety prior to 58.0 Hz or is it to say that the system frequency must never drop below 58.0 Hz? **Response:** The intent of the statement is that the system be designed such that frequency does not drop below 58.0 Hz for generator deficits up to and including 25%. In addition, the "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. Compliance with performance characteristics when the imbalance is greater than 25 % is not required by this standard. The SDT believes that proposed performance characteristics values are achievable for generator deficits up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.
PPL Generation	No Revise the design parameter as noted in the comments	Some existing generating facilities may have equipment limitations or specific protection issues which require the generator to trip at a frequency level above 58 Hz. This can result in a mis-coordination between the UFLS program and the generator protective settings. The 58 Hz value can be used as the guideline, but provision must be included to allow deviation from the guideline if mis-coordination of UFLS/Generator Frequency protective settings exist and valid technical reasons are provided by a legacy generating facility. See comment to question 1 for further details.
Response: The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: “To ensure that generators will not trip off-line during specified voltage and frequency excursions.” The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.		
Midwest ISO	No Revise the design parameter as noted in the comments	We understand that the 25% stated in the question represents the amount of load at system peak that could be shed by UFLS relays. If our understanding is correct, we support the design parameter and request that the drafting team make it clearer in the characteristics that this is based on system peak load. If not, we request the drafting to change the design parameter to match our understanding.
Response: The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The intent is that this would work		

Organization	Question 2	Question 2 Comments:
for any load level (peak, off-peak, etc.). The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.		
PJM	No Revise the design parameter as noted in the comments	In Item 4, the statement “at least 25 percent” should be changed to “at most 25 percent”. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. As it is currently worded, the requirement is almost impossible to meet unless all load is on UFLS. We do not believe this was the intent of the drafting team. UFLS should be used as a safety net, based on installation requirements rather than performance requirements. As it is currently worded, if your UFLS load shedding does not arrest a blackout, you could potentially be found non-compliant. **Response:** The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6).
Florida Reliability Coordinating Council	No Revise the design parameter as noted in the comments	The context of the phrase “identified island” requires clarification. We read the characteristics document to say the Regional Entity is required to develop a standard with UFLS that specifies the entity(s) responsible for identifying potential islands. We believe this means that the Regional Entity will name a group, such as the FRCC Stability Working Group to determine any islands that should meet the requirements of paragraph 2 in the characteristics document. However, we feel that the characteristic could potentially be misinterpreted as requiring the identification of ?any island? that has the possibility of being formed as the result of a system disturbance. It is not appropriate for these characteristics to require every possible island to meet the load mismatch criteria. **Response:** It is not the intent to identify every possible island or perform an exhaustive analysis. However, it is necessary to identify island(s) as a basis for designing the UFLS program (Requirement R5). The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5. The SDT believes that analysis to determine islands does not need to predict how island boundaries might form in future events. The characteristics should make it clear that the program design should protect significant islands that could be created with credible multiple contingencies. **Response:** The SDT agrees with the spirit of this comment. Requirement R3 will require the group of Planning Coordinators to develop criteria, considering historical events and system studies, to select portions of the Bulk

Organization	Question 2	Question 2 Comments:
		Electric System that may form islands.
Florida Power & Light Co.	No Revise the design parameter as noted in the comments	There may be low probability scenarios where islanding occurs with a load and generation imbalance significantly higher than 25%. The proposed wording could be interpreted to include any conceivable combination of contingencies and operating conditions that leads to islanding. The words at least 25% should be replaced with up to 25%. Alternatively the words identified island(s) could be removed to prevent such an expansive interpretation.
Response: The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5.		
Exelon	No Revise the design parameter as noted in the comments	The wording in Requirement 4 is such that the phrase 'at least 25 per cent imbalance' should be changed to 'a maximum of 25 per cent imbalance'. There should be a size specification on 'identified island' such that it is meaningful to the bulk electric system.
Response: The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5.The SDT disagrees that there should be a size specification for islands, but has modified the requirement to apply to islands containing portions of the Bulk Electric System. The islands identified should be able to meet the performance characteristics for the given conditions.		
Ameren	No Revise the design parameter as noted in the comments	We agree that NERC should establish a minimum percentage of peak load that should be used for in design of UFLS. **Response:** The 25% represents the imbalance between load and generation not necessarily the amount of load to be included in the UFLS program. However, the NERC SDT should provide reasons for their recommendation. **Response:** The 25% represents the imbalance between load and generation not necessarily the amount of load to be included in the UFLS program. The SDT selected the design level of imbalance between load and generation based on a review of the bases for the existing UFLS programs, and notes that it may be necessary for UFLS programs to shed more than 25% of load in order to achieve the performance requirements in Requirement R6. Again, we suggest that regions and subregions within the same interconnection should coordinate their UFLS design parameters. **Response:** Characteristic 3 (Requirement R4) was intended to require that the regional standards ensure

Organization	Question 2	Question 2 Comments:
		coordination occurs on an inter-regional basis.
Alliant Energy	No Revise the design parameter as noted in the comments	The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard. Throughout NERC characteristic list, the words “conditions resulting from an imbalance between load and generation of at least 25%” are used in relation to stated performance objectives. The words “of at least” create confusion as well as the undefined term “imbalance”. The MRO has assumed this means that criteria must be met at the maximum overload level each Regions UFLS program is designed to cover, with all Regions having to shed a minimum of at least 25% of system load. However, this could also mean that criteria only has to be met for a 25% imbalance. This needs to be more clearly stated. The MRO agrees with the concept of NERC establishing a minimum load shedding level for all regions, but we do not know what a 25% imbalance is supposed to be. The definition of imbalance is not given but there is a definition that is common to the subject of UFLS, where overload = OL = (remaining generation — load)/ (remaining generation). To us, imbalance = OL, then: OL = -.25 = (gen ? load)/gen = (.8-1)/.8 This implies 20% load shedding. A 20% load shedding requirement seems a little low. A 25% minimum load shedding requirement seems more reasonable, but each Region would need to consider if that is adequate to satisfy their internal needs. In any event, minimum load shedding requirements should be explicitly stated as X% of load. **Response:** The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. We agree that a 20% load shedding requirement is low; however, the proposed definition implies a minimum load shedding of 25% as the commenter anticipated. The 58.0 Hz appears to have more of a philosophical basis rather than being solely related to generation protection

Organization	Question 2	Question 2 Comments:
		needs. If generation protection is the issue, then a 58 Hz minimum frequency criteria would not be appropriate for all islands. An island consisting of hydro units could easily accept minimum frequencies below 58 Hz for extended periods. **Response:** The basis for the performance characteristics is coordination with generation protection. We agree that hydro units have wider frequency bands, but any island would not necessarily consist only of hydro units. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of interconnection. As a practical matter, 58 Hz, as average system frequency, is probably a reasonable minimum frequency target for design work, at least for programs that shed 30% load or less. UFLS programs which need to shed more load can increase starting frequencies to improve the minimum frequency to some extent, but may need to accept momentary dips below 58 Hz provided this coordinates with overall generation protection. If this becomes NERC performance criteria, then we anticipate there needs to be a way to allow exceptions when appropriate. **Response:** The SDT believes that 58 Hz is achievable for an imbalance up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. We also have concerns that minimum frequency seen in simulations is quite subjective, it depends on many specific details such as the specific overload level modeled, as well as the assumptions made for load damping, system inertia, UFLS details including total tripping times of load, capacitor tripping, governor response, etc. It is easier at the Regional level to resolve what range of conditions/assumptions/modeling issues need to be considered. **Response:** The SDT agrees that many factors affect simulation performance and need to be worked out by the Planning Coordinators during the design of the UFLS program. If any generators have unreasonable frequency characteristics that can be changed, then the Standard should require them to make appropriate changes. **Response:** This is not the intent of the proposed standard. The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: “To ensure that generators will not trip off-line during specified voltage and frequency excursions.”

Organization	Question 2	Question 2 Comments:
E.ON U.S.	No Revise the design parameter as noted in the comments	See Response to Question 9.
Response: Please see our response to your comment to Question 9.		
Manitoba Hydro	No Revise the design parameter as noted in the comments	While 58 Hz may be appropriate for thermal units, hydro units can operate at lower frequencies. Manitoba Hydro's system is predominantly hydro units, and given our system topology, a 58 Hz cut off is not appropriate to balance our load and generation when our system is separated from the BES. There should be some provision made for systems that are not tightly interconnected with the rest of the BES. Coordination of UFLS and generator protection within the region would then become a very important component of this performance metric.
Response: The basis for the performance characteristics is coordination with generation protection. We agree that hydro units have wider frequency bands, but any island would not necessarily consist only of hydro units. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of an interconnection. The SDT believes that 58 Hz is achievable for an imbalance up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
American Transmission Company	No Revise the design parameter as noted in the comments	With respect to the 25 percentage (Characteristic 4), rather than base UFLS program requirements on system conditions that may have variable underlying assumptions, a better approach might be to specify that UFLS programs be required to shed a minimum percentage of potential island load. **Response:** The SDT has elected to specify the imbalance rather than percentage of load shed so as not to be overly prescriptive on details of UFLS program design and to establish common performance requirements to facilitate coordination between the Planning Coordinators. In addition, the term, "imbalance between load and generation condition", is ambiguous and not clearly defined. Requiring ULFS programs be designed to shed at least a specified percent of potential island load is suggested. We interpret that the phrase "at least" implies that some Regional standards may require a higher percentage for different potential islands depending on the nature of load, generators, protection schemes, and dispatch within the island. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.

Organization	Question 2	Question 2 Comments:
		With respect to the 58.0 Hz value (Characteristic 4.1), we agree that this value seems reasonable in general. However, for some potential islands the appropriate frequency limit might be higher or lower than 58.0 Hz based on the nature of the load, generators, protection schemes, and dispatch in the island. **Response:** The SDT believes that 58 Hz is achievable for an imbalance up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. An absolute, continent-wide value may not be appropriate. The Characteristics could require that the proper frequency limit be investigated and established for each potential island. The proper frequency limit should be re-examined and changed, if necessary, each time the UFLS program for a potential island is re-assessed. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of an interconnection. If any generator limitations cause an unreasonable frequency limit and any of these limitations can be changed, then the Standard should require the Generator Owner to make appropriate changes. **Response:** This is not the intent of the proposed standard. The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: "To ensure that generators will not trip off-line during specified voltage and frequency excursions."
FirstEnergy Corp.	No Revise the design parameter as noted in the comments	The document should be revised to indicate imbalances of "25 percent or less" instead of "at least 25%". If a condition occurred that resulted in a very large imbalance, perhaps much greater than 50%, it may not be possible to arrest the frequency decline to no less than 58 Hz.
Response: The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/(load) of up to 25 percent within the identified island.		
NPCC	Yes	We agree that arresting frequency decline at no less than 58.0 Hz is an appropriate design parameter in most interconnections to ensure coordination with the generator trip requirements to be proposed in PRC-024. However, in some interconnections such as Québec, where generator physical characteristics result in generator underfrequency

Organization	Question 2	Question 2 Comments:
		trip settings below the curve to be proposed in PRC-024, Regional Reliability Standards should be allowed to permit exceptions to this design parameter.
Response: The SDT agrees that provisions for differences for interconnections within a region may be permitted in the form of a Variance as outlined in the NERC Rules of Procedures.		
Bandera Electric Cooperative	Yes	In general, the TRE UFLS SDT believes a UFLS program development for recovery from a frequency excursion in an event that utilizes a 25% contribution within a system allowed to go no further than 58.0 Hz is reasonable. Further, we believe this set of parameters makes sense from the standpoint of the protection of certain equipment from sustained low frequency operation. The parameters are also viewed as essential to the protection of components of low pressure condensing turbines, which are very sensitive to low frequency operation and can quickly develop sub-standard frequency resonance conditions which can lead to catastrophic failures. The TRE UFLS SDT however does question the nature of the wording of the performance criteria "...an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s)" Is the above stated incorrectly? Can the BES remain at a frequency greater than 58.0 Hz with a 25% imbalance between load and generation? Can generation maintain 125% loading without tripping and frequency collapse? Is the statement to imply that 25% of the load should be controlled by UFLS relays? Should the 25% be stated?
Response: The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. Compliance with performance characteristics when the imbalance is greater than 25 % is not required by this standard. The SDT believes that proposed performance characteristics values are achievable for generator deficits up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
PacifiCorp	Yes	Location of generation, load centers and associated transmission interconnections between specific geographical area impact the UFLS study results, especially in WECC region. It would be helpful if RRO would identify credible islands (bubbles) for UFLS studies within RRO and designate responsible parties to conduct overall UFLS studies as per PRC-006. **Response:** Requirement R3 will require the group of Planning Coordinators to develop criteria, considering historical events and system studies, to select portions of the Bulk Electric System that may form islands.
Southwest Power Pool	Yes	Our understanding is that we would continue to use a multi-step UFLS scheme similar to what is being utilized today and that drastic changes to these existing schemes would be avoided.
Response: This in line with the SDT's intent.		

Organization	Question 2	Question 2 Comments:
ERCOT	Yes	Arresting frequency before 58.0Hz for at least 25% load/generation mismatch is a reasonable expectation.
Southwest Power Pool	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not necessarily include those specific characteristics as requirements in the Regional Standard.
Southern Company Services, Inc	Yes	This is a reasonable parameter and apparently coordinates with the most recent thinking of the Generator Verification Standards Drafting Team.
SERC	Yes	This is a reasonable parameter and apparently coordinates with the most recent thinking of the Generator Verification Standards Drafting Team.
Progress Energy Carolinas, Inc.	Yes	This is a reasonable parameter and, based on our understanding, apparently coordinates the most recent thinking of the Generator Verification Standards Drafting Team.
Entergy	Yes	This is a reasonable parameter and apparently coordinates with the most recent thinking of the Generator Verification Standards Drafting Team.
City Water, Light & Power - Springfield, IL	Yes	
Grand River Dam Authority	Yes	
Florida Power & Light	Yes	
Louisiana Generqting, LLC	Yes	
Orrville Utilities	Yes	
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	

Organization	Question 2	Question 2 Comments:
We Energies	Yes	
Transmission Reliability Program	Yes	
Independent Electricity System Operator	Yes	
Duke Energy	Yes	
Georgia Transmission Corporation	Yes	

3. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that frequency does not remain below 58.5 Hz for greater than 10 seconds, cumulatively, and frequency does not remain below 59.5 Hz for greater than 30 seconds, cumulatively. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Summary Consideration:

The Underfrequency Load Shedding drafting team reviewed responses to this question and based on these comments made several conforming and/or clarifying changes to the performance characteristics (now Requirements).

- Many comments indicated that the term "cumulative" either should be removed or clarified because it is not easily tracked on a system level. The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. The standard does not require measuring compliance for actual events against the standard. The SDT has modified the performance characteristics (Requirement R6) to reflect this. Removal of the word "cumulative" does not preserve the intent of the performance characteristic.
- Several comments offered recommendations to revise the performance characteristic from 59.5 Hz to 59.3 Hz for 30 seconds. The SDT had selected the original performance characteristics to coordinate with typical turbine operating characteristics. Based on these comments the SDT revised the performance characteristics (Requirement R6.2) from 59.5 Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics.
- Several comments offered recommendations to revise the performance characteristic from 58.4 Hz to 59.4 Hz for up to nine minutes and continuous above 59.4 Hz. Other comments supported the performance characteristic as proposed by the SDT. Based on this support the SDT still proposes 58.5Hz for 10 seconds. The suggested settings do not coordinate with generator under-frequency time durations allowed by manufacturers.
- Some responses to this question indicate that it is more appropriate for the Planning Coordinators associated with the individual regions/islands to decide the appropriate design values, while still coordinating with other regions/islands. These responses indicated that most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. The SDT clarifies that the performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard.

Several responses to this question reiterate concerns regarding coordination with the PRC-024 drafting team expressed in prior questions. The SDT clarifies that it coordinated with the PRC-024 Generator Verification drafting team by providing the generator tripping curves to ensure that the performance characteristics do not conflict with the generator tripping curves.

Several responses to this question reiterate concerns regarding the 25% imbalance (at system peak) expressed in prior questions. The SDT clarifies that the 25% represents the imbalance between load and generation not the amount of load at system peak to be shed. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.

Organization	Question 3	Question 3 Suggested Revisions:
Grand River Dam Authority	No – Revise the design parameter as noted in the comments	What is the definition of cumulatively? Is this from the start of the event (UF), or is during the previous number of minutes, or from the beginning of time? It would appear that a better choice of a word is in order. **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. The standard does not require measuring compliance for actual events against the standard. The SDT has modified the performance characteristics (Requirement R6) to clarify. What does the load imbalance have to do with the UF decision? You either have UF or you do not, regardless of load imbalance. Or is there an intent to take no action on an UF event if there is a load imbalance less than 25%. **Response:** The SDT's intent is to address imbalances up to and including 25%. It is the SDT's intent to take action for imbalances up to and including 25%.
ERCOT	No – Revise the design parameter as noted in the comments	Operating to these design parameters seems reasonable. However, maybe the NERC standard characteristic should enforce the Region to have a methodology for determining these levels; Regional Standard should have the methodology for setting the levels to be met. Alternatively, the standard characteristic requirement should specify parameters for each Interconnection that are more technically suitable to the characteristic of each Interconnection.
Response: The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The performance characteristics are also intended to coordinate with generation characteristics that are common to all interconnections.		
Florida Power & Light	No – Revise the design parameter as noted in the comments	The term cumulatively is not defined. How is this measured? Is this over the time of the event, over the life of equipment i.e. generators etc.
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. The SDT has modified the performance characteristics (Requirement R6) to clarify.		

Organization	Question 3	Question 3 Suggested Revisions:
American Electric Power (AEP)	No – Revise the design parameter as noted in the comments	Most UFLS schemes are designed to meet the time requirements proposed by this characteristic if the load/generation imbalance is 25% or less. If the load/generation imbalance is greater than 25%, manual operator intervention (load shedding) may be required to maintain system frequency. An operator can not meet the time requirements outlined by this characteristic. The "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes.
Response: The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
PPL Generation	No – Revise the design parameter as noted in the comments	See comments to question 1.Some existing generating facilities may have equipment limitations or specific protection issues which force the generator to trip at a frequency levels and operating times that are inconsistent with the characteristic identified above. This can result in a mis-coordination between the UFLS program and the generator protective settings. The above characteristic can be used as the guideline, but provision must be included to allow deviation from the guideline if mis-coordination of UFLS/Generator Frequency protective settings exist and valid technical reasons are provided by a legacy generating facility.
Response: The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: “To ensure that generators will not trip off-line during specified voltage and frequency excursions.” The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.		
Bandera Electric Cooperative	No – Revise the design parameter as noted in the comments	The TRE UFLS SDT recommends the NERC performance criteria be revised from 59.5 Hz to 59.3 Hz. 59.5 Hz is a frequency level that should be supported by high set relays, (59.7 Hz); and when high sets are activated, the next level of intervention should be 59.3 Hz for no more than 30 seconds.
Response: Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds.		
Midwest ISO	No – Revise the design parameter as noted in the comments	We understand that the 25% stated in the question represents the amount of load at system peak that could be shed by UFLS relays. If our understanding is correct, we support the design parameter and request that the drafting team make it clearer in the characteristics that this is based on system peak load. If not, we request the drafting to change the design parameter to match our understanding.

Organization	Question 3	Question 3 Suggested Revisions:
		Response: The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. These design parameters should be coordinated with typical turbine operating characteristics. The UFLS relays should shed load to prevent permanent turbine damage. It is our understanding that a typical turbine can operate at 59.5 Hz for 30 minutes rather than 30 seconds without experiencing loss of life. Was the 30 seconds at 59.5 Hz supposed to be 30 minutes? **Response:** The SDT selected the original performance characteristics to coordinate with typical turbine operating characteristics. The SDT did intend on 59.5 Hz for 30 seconds; however, based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics. What does cumulative mean here? Is it the total operating time over a week period, a day, a year, the life of turbine? If the system frequency dips below 59.5 Hz for 15 minutes today and dips below 59.5 Hz tomorrow for 15 minutes, does that mean the UFLS relays should operate? **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
PJM	No – Revise the design parameter as noted in the comments	Please refer to the comment above for question 2. The current draft RFC standard allows the first step of UFLS to begin at 59.3 Hz. Please consider reducing this requirement to 59.3 Hz in the NERC Standard. **Response:** Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds. When discussing cumulatively, when is the accumulation timer reset: after a minute, an hour, a year? **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
Florida Reliability Coordinating	No – Revise the design parameter as noted in the	Remove of the word “cumulatively” as it is undefined and could be interpreted in several ways, but we think the intent was for a consecutive time. We believe protection engineers would interpret the times as an inclusive time frame and not as a cumulative period beyond the time span given.

Organization	Question 3	Question 3 Suggested Revisions:
Council	comments	**Response**: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. The context of the phrase “identified island” requires clarification. (See comments for Question No. 2.) **Response:** See response to question No. 2
Florida Power & Light Co.	No – Revise the design parameter as noted in the comments	The meaning of the term cumulatively in this context is unclear. If redefined as specific to one event, it would still be an unnecessary qualifier that would be difficult to apply. Remove the term cumulatively
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
Exelon	No – Revise the design parameter as noted in the comments	RFC has determined and included in its draft standard that the first step of the UFLS program may be at 59.3 Hz. Please change the parameter to include RFC level.
Response: Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds.		
Progress Energy Carolinas, Inc.	No – Revise the design parameter as noted in the comments	This design parameter is appropriate except for the requirement to "not remain below 59.5 Hz for greater than 30 seconds." Relatively quick recovery above 58.5 is appropriate to minimize the possibility of generator trips. However, at 59.5 Hz, the possibility of generator trips is greatly reduced and a more reasonable recovery time should be allowed. Recommend this be changed to "not remain below 59.5 Hz for greater than 5 minutes." ANSI standard 37.106-2003 indicates that 59.5 Hz for 5 minutes provides adequate margin above typical generator damage curves. This change will help reduce the potential for overshoot while still providing sufficient margin. **Response:** Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics. Additionally, the word "cumulatively" (in Characteristics 4.3 and 4.4) should be removed. Cumulatively refers more to "cumulative machine damage" and is not easily tracked on a system level (nor is it necessary on a system level). **Response:** Removal of the word “cumulative” does not preserve the intent of the performance characteristic. Instead, the SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS

Organization	Question 3	Question 3 Suggested Revisions:
		program design.
Ameren	No – Revise the design parameter as noted in the comments	We believe that the proposed time for underfrequency operation is too restrictive. The proposed time of 30 seconds of operation at 59.5 Hz does not provide the system operators with enough time to attempt to bring generation on-line to remedy the frequency undershoot. Based on our practices, tripping of generation at 59.5 Hz is not necessary and if implemented may further exacerbate the frequency decline conditions. We agree that underfrequency operation is neither optimum nor desired, but the system needs to hold together as long as possible to be able to implement operational solutions. We suggest that the SDT to quantify the risks, including appropriate review of existing (not proposed) IEEE, ANSI and other standards, associated with operating the generating equipment at 59.5 Hz (0.992 p.u.) for more than 30 seconds to support their recommendation. **Response:** The intent of the load shedding program is to stabilize frequency automatically prior to operator intervention. We agree that tripping generation may further exacerbate conditions. The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: "To ensure that generators will not trip off-line during specified voltage and frequency excursions." The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop. We also suggest the SDT to clearly define the term "cumulatively"; For example, is it per event, per life of the equipment, or something else? **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
Alliant Energy	No – Revise the design parameter as noted in the comments	The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard.

Organization	Question 3	Question 3 Suggested Revisions:
		We do not agree with the specified maximum operating times associated with the specified off-nominal frequencies. The proposal to limit time below 59.5 Hz and above 60.5 Hz to 30 seconds looks like a typo. 59.5 Hz to 60.5 Hz is the range where units can run continuously with no accelerated loss of life. Perhaps “30 seconds” should have read “30 minutes” which is still only 66% of the time specified by the MRO program for f <= 59.5 Hz. As written, the proposed criteria for time spent below 59.5 Hz and above 60.5 Hz is unacceptable. The MRO UFLS report states that generation protection cannot trip any quicker than shown below, and that utilities that need to shed more than 30% of connected load will have to relax these times to allow their load shedding to play out. MRO generation protection time delay requirement: 45 minute, frequency <=59.5 Hz? 5 minute, frequency <= 59.3 Hz? 1.33 minute, frequency <= 59 Hz? 30 second, frequency <= 58.4 Hz? 7.5 second, frequency <= 58.0 Hz? instant trip at 57.6 Hz In the MRO UFLS study simulations, we estimated our worst-case time below 58.5 Hz would be approximately 9 seconds. Of course, this has to be qualified by saying “for our given assumptions”. These types of simulations only give approximate results. The proposal to limit time below 58.5 Hz to 10 seconds is going to be tight for a program which sheds more than 30% load. What we assume for governor action will have considerable effect on how much time is spent below 58.5 Hz. The MRO tried to design a program that will ensure frequency recovery even if we get no net governor response. The MRO study looked at a range of imbalances that an UFLS program has to respond to, and factored in uncertainties. 100?s of cases were run to cover a range of imbalances, range of damping assumptions, and a range of system based inertia. In looking at all of the results in total, the resulting time spent below a given frequency took on the form of a probability density function. Typical times below a given frequency are perhaps more representative of what the typical exposure is for generation. However we coordinated generation protection according to the worst case times with enough margin to provide a degree of comfort. The actual loss of life a generator will be exposed to for some arbitrary UFLS event will most often be less than what these generator protection trip settings reflect as the first line of defense is the load shedding program itself. Under most circumstances, we will never spend enough time in the frequency trip bands to actually trip generation. To view the full report of the MRO UFLS please see the MRO website:http://www.midwestreliability.org/03_reliability/assessments/report_draft_03_12_final_clean.pdf **Response:** The SDT selected the original performance characteristics to provide coordination with typical turbine operating

Organization	Question 3	Question 3 Suggested Revisions:
		characteristics. SDT did intend on 59.5 Hz for 30 seconds; however, based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics.
E.ON U.S.	No – Revise the design parameter as noted in the comments	See Response to Question 9.
Response: Please see our response to your comment to Question 9.		
Manitoba Hydro	No – Revise the design parameter as noted in the comments	Manitoba Hydro echo's the MRO's concerns: "The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. "
Response: The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard.		
CenterPoint Energy	No – Delete the design parameter	As stated previously, CenterPoint Energy believes this effort should be postponed. Alternatively, this proposed design parameter should be deleted until coordination with the PRC-024 drafting team can be firmly established. **Response:** The SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team (GV SDT) by providing the generator underfrequency performance curve to ensure that the performance characteristics do not conflict with the generator off nominal capability curve. The SDT will continue to coordinate with the GV SDT and we believe it does not matter whether PRC-006 or PRC-024 is approved first as long as this coordination exists. If the design parameter is not deleted, CenterPoint Energy recommends the following values to place proper balance and emphasis on system reliability as system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions: 58.4 Hz to 59.4 Hz for up to 9 minutes and continuous above 59.4 Hz. **Response:** Based on industry support the SDT still proposes 58.5Hz for 10 seconds. The suggested settings do not coordinate with generator under-frequency time durations allowed by manufacturers. Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still

Organization	Question 3	Question 3 Suggested Revisions:
		maintaining coordination with typical turbine operating characteristics.
FirstEnergy Corp.	No – Revise the design parameter as noted in the comments	1. Although we agree that there needs to be a low set-point duration of no greater than 10 seconds for frequencies below 58.5 Hz, we are not sure if the appropriate first set-point should be set at 59.5 Hz. Some systems may be able to function reliably at 59.4 Hz for more than 30 seconds, so we ask the SDT to investigate this or provide the technical rationale for choosing 59.5 Hz. **Response:** Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics. 2. When using the term "cumulatively" in this characteristic, when is the accumulation timer reset: a minute, an hour, a year? We are not clear if this is based on a design parameter or an "after-the-fact" performance review. We ask the SDT to provide clarification on this term. **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. 3. As stated previously, the document should be revised to indicate imbalances of "25 percent or less" instead of "at least 25%". The design parameters would not be achievable if an extremely high imbalance occurred. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/(load) of up to 25 percent within the identified island.
Entergy	No	Entergy experiences some under-frequency relay trips due to transient contributions from induction motors with UF relays set to trip at 59.3 Hz. Relay trip settings at 59.5 Hz will increase the likelihood of these nuisance trips with attendant two-hour restart times for large commercial / industrial loads. We suggest the 59.5 Hz, 30 second, requirement is an overly restrictive requirement and we believe the setting should be lowered to at least 59.3 Hz. Lowering this requirement will give regions greater latitude when developing the design requirements of their standard.
Response: Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics.		
American Transmission	No – Revise the design parameter	With respect to the 25 percentage (Characteristic 4), refer to comments for Question 2. **Response**: The SDT has elected to specify the imbalance rather than percentage of load shed so as not to be overly

Organization	Question 3	Question 3 Suggested Revisions:
Company	as noted in the comments	prescriptive on details of UFLS program design and to establish common performance requirements to facilitate coordination between regions. With respect to the 10-second and 30-second underfrequency values (Characteristic 4.2), these values may be reasonable in general. However, for some potential islands the appropriate frequency limits might be higher or lower based on the nature of the load, generators, protection schemes, and dispatch in the island. Absolute, continent-wide values may not be appropriate. The Characteristics could require that the proper frequency limits be investigated and established for each potential island. The proper frequency limit should be re-examined and changed, if necessary, each time the UFLS program for a potential island is re-assessed. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of an interconnection. If any generator limitations cause an unreasonable frequency limit and any of these limitations can be changed, then the Standard should require the Generator Owner to make appropriate changes. **Response:** This is not the intent of the proposed standard. The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: "To ensure that generators will not trip off-line during specified voltage and frequency excursions."
Indiana Municipal Power Agency	No – Revise the design parameter as noted in the comments	The term cumulatively is confusing. It either needs to be clarified or removed.
Response: Removal of the word "cumulative" does not preserve the intent of the performance characteristic. Instead, the SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
Duke Energy	No – Revise the design parameter as noted in the comments	The time frames stated in these criteria seem overly conservative. Thirty seconds at 59.5 Hz would likely create expensive and unnecessary relay setting changes. Recommend changing the requirement to "59.5 Hz for greater than 5 minutes." **Response:** Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics.

Organization	Question 3	Question 3 Suggested Revisions:
		The Generator Verification SDT (PRC-024) is evaluating the appropriate envelope for protection of generator equipment. The envelope established by these criteria must be coordinated with generator protection envelope. **Response:** The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: "To ensure that generators will not trip off-line during specified voltage and frequency excursions." The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop. The word "cumulatively" is confusing in this context. Since this is generally related to equipment and not system studies, recommend deleting "cumulatively" from the requirements. **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
PacifiCorp	Yes	same comment as item 2 to identify UFLS study bubble by RRO. Location of generation, load centers and associated transmission interconnections between specific geographical area impact the UFLS study results, especially in WECC region. It would be helpful if RRO would identify credible islands (bubbles) for UFLS studies within RRO and designate responsible parties to conduct overall UFLS studies as per PRC-006.
Response: Requirement R3 will require the group of Planning Coordinators to develop a procedure to investigate and locate portions of the Bulk Electric System that may form islands including how historical events and system studies were considered.		
Southwest Power Pool	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not necessarily include those specific characteristics as requirements in the Regional Standard.
Response: The SDT confirms that this was the original intent; however, the SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard that requires the Planning Coordinators to design UFLS programs that adhere to the performance characteristics (Requirement R6).		
Southern Company Services, Inc	Yes	No Additional Comment.
Louisiana Generqting,	Yes	

Organization	Question 3	Question 3 Suggested Revisions:
LLC		
Orrville Utilities	Yes	
City Water, Light & Power - Springfield, IL	Yes	
NPCC	Yes	
SERC	Yes	
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	
We Energies	Yes	
Transmission Reliability Program	Yes	
Independent Electricity System Operator	Yes	
Georgia Transmission Corporation	Yes	

4. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that the frequency overshoot resulting from operation of UFLS relays will not exceed 61.0 Hz for any duration and will not exceed 60.5 Hz for greater than 30 seconds, cumulatively. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Summary Consideration:

The UFLS Standard Drafting team reviewed comments to this question and made several conforming changes to the performance characteristics (now requirements).

- Numerous industry comments indicated that while this design parameter is appropriate as an overall system design obective the limits are overly restrictive and do not appear to coordinate with any equipment limitations. Based on these comments the SDT adjusted the characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).

- Several industry comments indicated that operating to these parameters appears reasonable; however, it would be preferrable if the SDT specify parameters for each interconnection that are more technically suitable to the characteristic of each interconnection. The SDT clarifies that the performance characteristics are intended to coordinate with generation characteristics that are common to all interconnections. In addition, the SDT believes that the performance characteristics are achieveable for imbalances up to and including 25%. For deficiencies up to 25% these performance characteristics must be met; however, for deficiencies exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

- Several industry comments indicated that “cumulative” needs clarification. The SDT clarifies that cumulative is “per event simulated” to verify that the performance characteristics are achieved by the UFLS program design. Various requirements were modified to reflect that cumulative is per event simulated.

- Several industry comments suggested that a mimium size of the postulated island should be specified and it should be of sufficient size to affect the Bulk Electric System and there should be a distinction with differing requirements between the entire Eastern Interconnection and a potential frequency overshoot in a much smaller identified island. The SDT believes that the UFLS programs must be designed such that all interconnected systems will meet common performance characteristics. Common performance characteristics facilitate coordination between regions. An island could be subject to other performance characteristics in addition to the common performance characteristics for imbalances greater than 25% if the Regional Entities develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. In addition, the SDT clarified requirements concerning identification of islands in Requirements R3, R4, and R5. The SDT disagrees that there should be a size specification for islands, but has modified the requirement to apply to islands

containing portions of the Bulk Electric System. The islands identified should be able to meet the performance characteristics for the given conditions.

Organization	Question 4	Question 4 Suggested Revisions:
NPCC	No – Revise the design parameter as noted in the comments	We agree this design parameter is appropriate as an overall system design objective. However, this objective cannot be met through the UFLS program design alone in the absence of adequate generating unit governing response. We recommend that applicability of this design parameter be limited to islands that exhibit a frequency response of at least 1 percent of peak island load per 0.1 Hz.
Response: Rather than changing applicability of this performance characteristic, the SDT adjusted the characteristic. Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds.		
ERCOT	No – Revise the design parameter as noted in the comments	Operating to these design parameters seems reasonable. However, maybe the NERC standard characteristic should enforce the Region to have a proof of methodology of determining these levels, Regional Standard should have the methodology for setting the levels to be met. Alternatively, the standard characteristic requirement should specify parameters for each Interconnection that are more technically suitable to the characteristic of each Interconnection. In addition to the comment; does the NERC SDT have supporting documentation for restricting frequency overshoot to 61Hz? Request NERC Generation Verification SDT for reasoning/explanation.
Response: The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The performance characteristics are also intended to coordinate with generation characteristics that are common to all interconnections. Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Florida Power & Light	No – Revise the design parameter as noted in the comments	Cumulatively needs to be defined. Is this cumulative over the event, cumulatively over the life of the equipment? The 61Hz and 60.5Hz limits are overly restrictive and do not appear to coordinate with any equipment limitations

Organization	Question 4	Question 4 Suggested Revisions:
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
American Electric Power (AEP)	No – Revise the design parameter as noted in the comments	UFLS schemes are designed to account for frequency overshoot by breaking the UFLS scheme up into separate steps (verified by dynamic simulation). Is the intent of this characteristic to specify parameters for the amount of load included in each UFLS step and/or to specify parameters for unit overspeed trip settings? Clarification is needed not only for the intent of this characteristic but also regarding the foundation of the timing requirements. In addition, the "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes.
Response: Unit overspeed trip relay settings are to be limited according to PRC-024. The UFLS performance characteristics are intended to coordinate with PRC-024 in order to prevent unnecessary loss of generation. Timing requirements need to be specified by the group of Planning Coordinators to prevent frequency overshoot above the performance characteristic values. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
PPL Generation	No – Revise the design parameter as noted in the comments	See comments to question 1.Some existing generating facilities may have equipment limitations or specific protection issues which force the generator to trip at a frequency levels and operating times that are inconsistent with the values identified above. This can result in a mis-coordination between the UFLS program and the generator protective settings. The above characteristic can be used as the guideline, but provision must be included to allow deviation from the guideline if mis-coordination of UFLS/Generator Frequency protective settings exist and valid technical reasons are provided by a legacy generating facility.
Response: The SDT believes that the generating equipment limitations should be addressed in the Project 2007-09: Generator Verification PRC-024 because part of the purpose of the standard (as stated in the SAR) is: "To ensure that generators will not trip off-line during specified voltage and frequency excursions." The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.		
Bandera Electric Cooperative	No – Delete the design parameter	The TRE UFLS SDT believes that the NERC standard should not define the frequency overshoot limit; instead, the NERC standard should state this as a requirement for the region to establish as part of a regional UFLS standard. For example, the NERC standard might state as follows: "The Regional Standard shall define the frequency overshoot it

Organization	Question 4	Question 4 Suggested Revisions:
		determines appropriate in arresting the imbalance between load and generation."
Response: The performance characteristics are intended to coordinate with generation characteristics that are common to all interconnections. The UFLS design parameters can be devised by the Planning Coordinator(s) and the SDT has assigned the Planning Coordinators this responsibility in the proposed standard.		
Louisiana Generqting, LLC	No – Revise the design parameter as noted in the comments	61Hz and 60.5Hz limits are overly restrictive and do not appear to coordinate with any equipment limitations
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Midwest ISO	No – Revise the design parameter as noted in the comments	We understand that the 25% stated in the question represents the amount of load at system peak that could be shed by UFLS relays. If our understanding is correct, we support the design parameter and request that the drafting team make it clearer in the characteristics that this is based on system peak load. If not, we request the drafting to change the design parameter to match our understanding. **Response:** The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. These design parameters should be coordinated with typical turbine operating characteristics. If a turbine can operate at 60.5 Hz for 30 minutes before experiencing any loss of life, the design parameters should reflect this. It is our understanding that a typical turbine can operate at 60.5 Hz for 30 minutes rather than 30 seconds without experiencing loss of life. Was the 30 seconds at 60.5 Hz supposed to be 30 minutes? **Response:** The SDT selected the original performance characteristics to provide coordination with typical turbine operating characteristics. Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).
Southern	No – Revise the	These parameters are overly restrictive. We recommend to change the statement to "will not exceed 61.5 Hz for any

Organization	Question 4	Question 4 Suggested Revisions:
Company Services, Inc	design parameter as noted in the comments	duration and will not exceed 60.5 Hz for greater than 5 minutes?" A frequency of 61.8 Hz results in a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin. ANSI standard 37.106-2003 indicates that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. Our proposed parameters allow time for generator governors to operate and for some load restoration to correct overshoot.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
PJM	No – Revise the design parameter as noted in the comments	"for any duration" is too difficult to meet. Substitute with a short time frame.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Florida Reliability Coordinating Council	No – Revise the design parameter as noted in the comments	The 61.0 hertz ceiling for frequency recovery seems too low. Is there any technical justification for this level? A more appropriate limit might be 61.8 hertz due to the number of governing systems that initiate auxiliary governor action at 103% overspeed. **Response:** Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that are developing generator requirements (PRC-024). Remove of the word “cumulatively”. (See comments for Question No. 3.) **Response:** Removal of the word “cumulative” does not preserve the intent of the performance characteristic. Instead, the SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. The context of the phrase “identified island” requires clarification. (See comments for Question No. 2.) **Response:** See our response to question No. 2

Organization	Question 4	Question 4 Suggested Revisions:
SERC	No – Revise the design parameter as noted in the comments	These parameters are overly restrictive. We recommend to change the statement to "will not exceed 61.5 Hz for any duration and will not exceed 60.5 Hz for greater than 5 minutes?" A frequency of 61.8 Hz results in a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin. ANSI standard 37.106-2003 indicated that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. Our proposed parameters allow time for generator governors to operate and for some load restoration to correct overshoot.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Entergy	No	We agree with and support the SERC comments.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Northeast Utilities	No – Revise the design parameter as noted in the comments	We do not believe all generator controls are sufficiently responsive to enable this design parameter. A longer response time may be needed, or a significant improvement in governing response for connected generators.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Florida Power & Light Co.	No – Revise the design parameter as noted in the comments	A technical justification of the proposed over frequency limits does not appear to be posted with the generator verification SDT information. A target over frequency limit of 61.8 hertz is used within the FRCC. The 61.0 hertz and 60.5 hertz for 30 seconds appear to be unnecessarily low. **Response:** Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that are developing generator requirements (PRC-024). The words at least 25% should be replaced with up to 25% for the reasons discussed above.

Organization	Question 4	Question 4 Suggested Revisions:
		Response: The 25% represents the imbalance between load and generation not the amount of load to include in the UFLS program. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The word cumulatively should be removed. **Response:** Removal of the word "cumulative" does not preserve the intent of the performance characteristic. Instead, the SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
Exelon	No – Revise the design parameter as noted in the comments	There should be a distinction and differing requirements between the entire Eastern Interconnection and a potential frequency overshoot in a much smaller identified island. Also, the minimum size of the postulated island should be specified here. It should be of sufficient size to affect the bulk electric system.
Response: The UFLS program must be designed such that all interconnected systems will meet common performance characteristics. Common performance characteristics facilitate coordination between regions. An island could be subject to other performance characteristics in addition to the common performance characteristics for imbalances greater than 25% if the Regional Entities develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5. The SDT disagrees that there should be a size specification for islands, but has modified the requirement to apply to islands containing portions of the Bulk Electric System. The islands identified should be able to meet the performance characteristics for the given conditions.		
Progress Energy Carolinas, Inc.	No – Revise the design parameter as noted in the comments	These parameters are overly restrictive. We recommend to change the statement to "will not exceed 61.5 Hz for any duration and will not exceed 60.5 Hz for greater than 5 minutes?" A frequency of 61.8 Hz results in a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin. ANSI standard 37.106-2003 indicated that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. Our proposed parameters allow time for generator governors to operate and for some load restoration to correct overshoot.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Ameren	No – Revise the design parameter	We believe that these over frequency parameters are overly restrictive. We suggest that the SDT to quantify the risks, including appropriate review of existing (not proposed) IEEE, ANSI and other standards, associated with operating the

Organization	Question 4	Question 4 Suggested Revisions:
	as noted in the comments	generating equipment above 60.5 Hz for more than 30 seconds to support their recommendation. We also suggest the SDT to clearly define the term "cumulatively"; For example, is it per event, per life of the equipment, or something else?
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024). The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
Alliant Energy	No – Revise the design parameter as noted in the comments	This a subjective performance criteria as modeling details such as load damping assumptions, inertia assumptions, and governor response assumption will all have considerable effect on performance. This type of performance objective is best evaluated and determined at the Regional level or some mechanism needs to be in place to allow aggressive load shedding programs some latitude on this. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. There are cases where overshoots above 61 Hz could be accepted for short periods. The type of units in the island also have to be considered. Hydro systems have fewer off-nominal frequency restrictions. The 30 second time limit for operating above 60.5 Hz is not at all appropriate. Units can operate continuously at 60.5 Hz with no accelerated loss of life. They can run slightly above this for a long time. Could this be a typo? Was the intention to establish at 30 minute limit? **Response:** Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).
E.ON U.S.	No – Revise the design parameter as noted in the comments	See Response to Question 9.
Response: Please see our response to your comment to Question 9.		
Manitoba Hydro	No – Revise the design parameter	Again, Manitoba Hydro echo's the MRO's concerns. Each region should determine the maximum overshoot based on

Organization	Question 4	Question 4 Suggested Revisions:
	as noted in the comments	its system topology, how it was planned and designed and the region's requirements.
Response: The performance characteristics are intended to coordinate with generation characteristics that are common to all interconnections and ensure coordination among the programs the Planning Coordinators are required to design. The UFLS design parameters can be devised by the Planning Coordinator(s) and the SDT has assigned the Planning Coordinators this responsibility in the proposed standard.		
CenterPoint Energy	No – Delete the design parameter	As stated previously, CenterPoint Energy believes this effort should be postponed. Alternatively, this proposed design parameters should be deleted until coordination with the PRC-024 drafting team can be firmly established. If the design parameter is not deleted, CenterPoint Energy recommends a value of 61.5 Hz instead of 61.0 Hz to place proper balance and emphasis on system reliability as system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that are developing generator requirements (PRC-024).		
FirstEnergy Corp.	No – Delete the design parameter	1. When using the term "cumulatively" in this characteristic, when is the accumulation timer reset: a minute, an hour, a year? We are not clear if this is based on a design parameter or an "after-the-fact" performance review. We ask the SDT to provide clarification on this term. **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. 2. We recommend that this design parameter be deleted. We feel that the characteristic is overly prescriptive. Although frequency overshoot may be a concern in some regions, it is not in all regions. In many regions the generators would automatically re-adjust to lower frequency. **Response:** This is a concern for all islands and interconnected systems. The requirement (Requirement R6.3) ensures coordination with the UFLS program and generator limitations. Governing response to over-frequency conditions should be accounted for in the design of the UFLS program.
American Transmission	No – Revise the design parameter as noted in the	With respect to the 25 percentage (Characteristic 4), refer to comments for Question 2. **Response:** The SDT has elected to specify the imbalance rather than percentage of load shed so as not to be overly

Organization	Question 4	Question 4 Suggested Revisions:
Company	comments	prescriptive on details of UFLS program design and to establish common performance requirements to facilitate coordination between regions. With respect to the continuous and 30-second overfrequency values (Characteristic 4.3), these values may be reasonable in general. However, for some potential islands the appropriate frequency limits might higher or lower based on the nature of the load, generators, protection schemes, and dispatch in the island. Absolute, continent-wide value may not be appropriate. The Characteristics could require that the proper frequency limit be investigated and established for each potential island. The proper frequency limit should be re-examined and changed if necessary each time the UFLS program for a potential island is re-assessed. If any generator limitations cause an unreasonable frequency limit and any of these limitations can be changed, then the Standard should require the Generator Owner to make appropriate changes. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of an interconnection.
Indiana Municipal Power Agency	No – Revise the design parameter as noted in the comments	The term cumulatively is confusing. It either needs to be clarified or removed.
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
Duke Energy	No – Revise the design parameter as noted in the comments	These parameters seem too restrictive. Recommend changing the statement to "will not exceed 61.5 Hz for any duration and will not exceed 60.5 Hz for greater than 5 minutes?" This is recommended because a frequency of 61.8 Hz is a 3% generator overspeed, which should be avoided. An absolute limit of 61.5 Hz provides an adequate margin. Also, ANSI standard 37.106-2003 indicated that 60.5 Hz for 5 minutes provides adequate margin below generator damage curves. The recommended parameter changes allow time for generator governors to operate and for some load restoration to correct overshoot.
Response: Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024).		
Southwest Power	Yes	The Regional Entity intent is to address the performance characteristics as recommended by the NERC SDT, but not

Organization	Question 4	Question 4 Suggested Revisions:
Pool		necessarily include those specific characteristics as requirements in the Regional Standard.
Response: The SDT confirms that this was the original intent; however, the SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard that requires the Planning Coordinators to design UFLS programs that adhere to the performance characteristics (Requirement R6).		
We Energies	Yes	
Buckeye Power, Inc.	Yes	
Orrville Utilities	Yes	
City Water, Light & Power - Springfield, IL	Yes	
Grand River Dam Authority	Yes	
PacifiCorp	Yes	
Transmission Reliability Program	Yes	
Independent Electricity System Operator	Yes	
Georgia Transmission Corporation	Yes	

5. As proposed, each regional UFLS standard must require that, for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent within an interconnection, region, or identified island(s) within or between regions, the UFLS must act such that the Bulk Electric System voltage during and following UFLS operations is controlled such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than 6 seconds cumulatively, and does not exceed 1.10 for longer than 1 minute cumulatively. Do you agree with this design parameter? If you disagree, please identify whether you believe this design parameter should be deleted or revised.

Summary Consideration:

The UFLS Standard Drafting team reviewed comments to this question and made several conforming changes to the performance characteristics (now requirements). In addition, the team considered the comments and provided clarifying responses.

- Several comments expressed concern that this performance characteristic is out of place because as load is rejected to correct the frequency problem the voltage should climb. The SDT clarifies that they feel it is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.
- Several comments expressed concern that the underfrequency relays are not monitored or supervised by a volts/ hertz element and do not operate or block based on the Volts / hertz. The underfrequency relays typically do have undervoltage blocking which will block underfrequency relay operation for low voltage, but the UFLS relays have no capability to control voltage. Therefore, the UFLS relays cannot control voltage level or volts/ hertz and this requirement should be omitted from the UFLS standard characteristics.The SDT agrees with the comment; however, the intent is that over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances.
- Comments expressed confusion regarding whether this is a planning characterisitc for simulation of the UFLS or a post event measurement for compliance. The SDT clarified that this is a planning characteristic for simulation based design verification studies. It is not a post-event measurement for compliance. The proposed standard has been modified to clarify this point.
- Several comments indicated that the standard characteristic requirement should specify how to determine to which buses these voltage requirements apply for each Interconnection, at a minimum, and preferably for each Region. The SDT made a clarifying change to Requirement R6.4 which further specifies the locations to which these voltage requirements apply.

Organization	Question 5	Question 5 Suggested Revisions:
Grand River Dam Authority	No – Revise the design parameter as noted in the comments	This seems to be out of place in an UFLS scheme and may belong in an OV scheme. As load is rejected to correct the frequency problem, the voltage should climb. The generators, with the VRs, may or may not see the problem. This seems more like a hope than an item that someone can accomplish. Studies may indicate that there is no problem. But if they show a problem, what can be done? Install shunt reactors which may not help the frequency problem????
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
ERCOT	No – Revise the design parameter as noted in the comments	Is this just a planning characteristic for simulation of the UFLS, or a post event measurement for compliance? If it is included in the post event compliance analysis then it needs to be more specific on what voltage(s) are to be measured and meet the design parameters. Is it every Bus Voltage in the BES? Or a subset of critical buses for measurement? **Response:** This is a planning characteristic for simulation based design verification studies. It is not a post-event measurement for compliance. The proposed standard has been modified to clarify this point. Perhaps the NERC Standard Characteristic requests that each Region establish a methodology for determining a list of critical buses and these bus voltages are to be used for the UFLS and post event compliance analysis. Alternatively, the standard characteristic requirement should specify how to determine to which buses these voltage requirements apply for each Interconnection, at a minimum, and preferably for each Region. **Response:** The SDT modified Characteristic 4.4 (Requirement R6.4) to further specify the location (Requirements R6.4.1 and R6.4.2).
Florida Power & Light	No – Revise the design parameter as noted in the comments	The term cumulatively needs to be defined
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
American Electric Power (AEP)	No – Delete the design parameter	The foundation of the timing requirements needs to be clarified. **Response:** The technical basis for the performance characteristics was developed through a review of relevant

Organization	Question 5	Question 5 Suggested Revisions:
		industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. The SDT included more details regarding the technical justification for the performance characteristics in the comment form background (including specific IEEE standards). In addition, the "at least 25 percent" designation should be changed to "25 percent and below". Any imbalance greater than 25-30% is beyond the scope of most UFLS schemes. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.
Southwest Power Pool	No – Delete the design parameter	The UFLS system consists of underfrequency relays. The underfrequency relays are not monitored or supervised by a volts/ hertz element and do not operate or block based on the Volts / hertz. The underfrequency relays typically do have under voltage blocking which will block underfrequency relay operation for low voltage, but the UFLS relays have no capability to control voltage. Therefore, the ufls relays cannot control voltage level or volts/ hertz and this requirement should be omitted from the UFLS standard characteristics.
Response: The SDT agrees with the comment; however, the intent is that over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances.		
Bandera Electric Cooperative	No – Revise the design parameter as noted in the comments	The TRE UFLS SDT feels that, due to the interplay between load and generation components during a firm load shedding event, it would seem impractical to decompose their individual contributions to the volts/Hz ratio; therefore, compliance enforcement would likely prove to be impossible. **Response:** This is a planning characteristic for simulation based design verification studies. It is not a post-event measurement for compliance. The TRE UFLS SDT feels that the NERC standard should not specify the relay coordination requirements with generation protection relays. Instead, the NERC standard should state as a requirement for each region to establish as part of the UFLS standard a planning study to determine adequacy and consistency with other standards. For example, the NERC standard might state as follows: "The Regional Standard shall address the requirement for the UFLS to coordinate with existing regional generation relaying requirements." As written, the proposed performance criteria may conflict with ERCOT's Operating Guide 3.1.4.6 where v/Hz is specified. **Response:** The UFLS program must be designed such that all interconnected systems will meet common

Organization	Question 5	Question 5 Suggested Revisions:
		performance characteristics. The SDT acknowledges that ERCOT 3.1.4.6 (1.16 pu v/Hz for 1.5 seconds); is more conservative than the proposed performance characteristic (Requirement R6.4).
Louisiana Generqting, LLC	No – Revise the design parameter as noted in the comments	the interplay between the generation control and the load shedding programs will make it difficult to meet this requirement and cumulatively need to be defined.
Response: The SDT considers that the performance characteristic is achievable and a necessary requirement. Lack of coordination between generation control and under frequency load shedding program could result in inappropriate generator tripping and result in a failure of the overall program. The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.		
Midwest ISO	No – Delete the design parameter	V/Hz design parameters are appropriate for generation protection. We don't believe that is should be considered here as design parameter.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
Southern Company Services, Inc	No – Delete the design parameter	A volts per hertz requirement is more appropriate in a generator protection standard.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
PJM	No – Delete the design parameter	Add the units after the numbers mentioned (p.u. V/Hz). **Response:** The SDT believes that it is correct as stated. When discussing cumulatively, when is the accumulation timer reset: after a minute, an hour, a year? **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics

Organization	Question 5	Question 5 Suggested Revisions:
		are achieved by the UFLS program design.
Florida Reliability Coordinating Council	No – Revise the design parameter as noted in the comments	Replace the words "Bulk Electric System" with "generator terminal". The volts per hertz limits contained in 4.4 correspond to recommendations typical for generators. The temporary overvoltages (TOV) that will follow islanding with UFLS action tend to be significantly higher on the EHV transmission system since generators will be absorbing Vars and pulling voltage down. The EHV TOV capabilities are generally much higher than generator V/Hz limits and may be more variable due to individual grid design practices regarding basic insulation level and lightning arrester ratings. **Response:** The buses for which this should apply should be determined according to volts per Hz limits on applicable equipment, etc. In addition, SDT clarifies that the requirement does not address overvoltage limits. The SDT modified Characteristic 4.4 (Requirement R6.4) to further specify the location (Requirements R6.4.1 and R6.4.2). Remove of the word “cumulatively”. (See comments for Question No. 3.)The context of the phrase “identified island” requires clarification. (See comments for Question No. 2.) **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design.
SERC	No – Delete the design parameter	This requirement is very difficult to measure. A volts per hertz requirement is more appropriate in a generator protection standard.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
We Energies	No – Revise the design parameter as noted in the comments	This design parameter should be revised to clearly indicate that the base value of the per unit frequency component of the Volts per Hz ratio is 60 Hz to avoid any confusion with the scheduled frequencies that are used for time error correction (e.g. 59.98 or 60.02 Hz). **Response:** The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. We expect that all design simulations will be performed at a base frequency of 60 Hz. In addition, since the values listed in this design parameter are commonly used for generator volts per hertz protection settings, perhaps the system limits should have slightly lower allowable times so the generators do not

Organization	Question 5	Question 5 Suggested Revisions:
		trip undesirably during this period. **Response:** The technical basis for the performance characteristics was developed through a review of relevant industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. The SDT modified Characteristic 4.4 (Requirement R6.4) to further specify the location (Requirements R6.4.1 and R6.4.2).
Florida Power & Light Co.	No – Revise the design parameter as noted in the comments	Replace the words Bulk Electric System voltage with generator terminal voltage. The volts per hertz limits contained in 4.4 correspond to recommendations typical for generators. The temporary overvoltages (TOV) that will follow islanding with UFLS action tend to be significantly higher on the EHV transmission system since generators will be absorbing Vars and pulling voltage down. The EHV TOV capabilities are generally much higher than generator V/Hz limits and may be more variable due to individual grid design practices regarding basic insulation level and lightning arrester ratings. **Response:** We agree that the buses for which this should apply should be determined according to volts per Hz limits on applicable equipment, etc. In addition, SDT clarifies that the requirement does not address overvoltage limits. The SDT modified Characteristic 4.4 (Requirement R6.4) to further specify the location (Requirements R6.4.1 and R6.4.2). The words at least 25% should be replaced with up to 25% for the reasons discussed above. **Response:** The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.
Progress Energy Carolinas, Inc.	No – Delete the design parameter	This requirement is very difficult to measure from a transmission system perspective. A volts per hertz requirement is more appropriate in a generator protection standard.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
Ameren	No – Delete the design parameter	We believe that a volts per hertz requirement is more appropriate in a standard that deals with generation protection issues.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to		

Organization	Question 5	Question 5 Suggested Revisions:
prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
Alliant Energy	No – Delete the design parameter	This a subjective performance criteria as modeling details such as load damping assumptions, inertia assumptions, and governor response assumption will all have considerable effect on performance. This type of performance objective is best evaluated and determined at the Regional level or some mechanism needs to be in place to allow aggressive load shedding programs some latitude on this. There are cases where overshoots above 61 Hz could be accepted for short periods. The type of units in the island also have to be considered. Hydro systems have fewer off-nominal frequency restrictions. **Response:** The UFLS program must be designed such that all interconnected systems will meet common performance characteristics. Common performance characteristics facilitate coordination between regions. The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The 30 second time limit for operating above 60.5 Hz is not at all appropriate. Units can operate continuously at 60.5 Hz with no accelerated loss of life. They can run slightly above this for a long time. Could this be a typo? Was the intention to establish at 30 minute limit? **Response:** Based on industry comment the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that are developing generator requirements (PRC-024).
E.ON U.S.	No – Revise the design parameter as noted in the comments	See Response to Question 9.
Response: Please see our response to your comment to Question 9.		
Manitoba Hydro	No – Revise the design parameter as noted in the comments	Again, Manitoba Hydro echo's the MRO's concerns. Each region should determine the volts per Hz based on its system topology, how it was planned and designed and the region's requirements.
Response: The UFLS program must be designed such that all interconnected systems will meet common performance characteristics. Common performance		

Organization	Question 5	Question 5 Suggested Revisions:
characteristics facilitate coordination between regions. The SDT believes that performance characteristics are achievable for imbalances up to and including 25%. For an imbalance up to and including 25% these performance characteristics must be met; however, for an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
PacifiCorp	No – Revise the design parameter as noted in the comments	No issues related to the 1.18 V/Hz proposed requirement. The existing PacifiCorp standard overexcitation trip characteristic follows an inverse time characteristic for values over 1.08 V/Hz. The curve is set to protect a thermal unit per the manufacturer's recommendation. A typical curve will initiate a unit trip if the overexcitation value is 1.10 V/Hz for 291 seconds (4 min 51 seconds) a time delay that is more conservative than the manufacturer's recommendation. Overexcitation values are not typically accumulated. Protective relays implemented to protect the thermal fleet at PacifiCorp to not accumulate Volts/Hertz values. If the overexcitation element starts timing, then drops out, and once again starts timing the initial overexcitation event does not lower the trip time for the second event. ?????
Response: It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping. The SDT acknowledges that the PacifiCorp V/Hz protection application is more conservative than the proposed performance characteristic (Requirement R6.4).		
Transmission Reliability Program	No – Revise the design parameter as noted in the comments	Both question #5 above and the third bullet on page 3 of the summary document (starting with Bulk Electric System voltage . . . .) appear to be inconsistent regarding the "time durations" in the standard's characteristics section 4.4. Section 4.4 states: Control Bulk Electric System voltage during and following UFLS operations such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than "two seconds" cumulatively, and does not exceed 1.10 for longer than "45 seconds" cumulatively. The language in question #5 above respectively references 6 seconds cumulatively and 1 minute cumulatively. Based on the discussion on page 3, the shorter timeframes shown in section 4.4 are the correct values.
Response: Performance characteristic 4.4 states: Control voltage during and following UFLS operations such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than two seconds cumulatively, and does not exceed 1.10 for longer than 45 seconds cumulatively. The comment form does not reflect the characteristic but should have. This was an oversight.		
CenterPoint Energy	No – Delete the design parameter	As stated previously, CenterPoint Energy believes this effort should be postponed. Alternatively, this proposed design parameter should be deleted until coordination with the PRC-024 drafting team can be firmly established. If the design parameter is not deleted, CenterPoint Energy believes the proposed values are adequate to place proper balance and emphasis on system reliability as system performance can vary widely depending upon system load and the composition of assumed on-line generation under various conditions.
Response: While the Project 2007-09 – Generator Verification (PRC-024) standard drafting team is addressing generator tripping requirements for off-nominal frequency and voltage, they are not explicitly addressing V/Hz protection. This performance characteristic (Requirement R6.4) is based on applicable IEEE		

Organization	Question 5	Question 5 Suggested Revisions:
standards and need not be delayed or deleted to allow coordination with the Generator Verification SDT.		
FirstEnergy Corp.	No – Delete the design parameter	1. When using the term "cumulatively" in this characteristic, when is the accumulation timer reset: a minute, an hour, a year? We are not clear if this is based on a design parameter or an "after-the-fact" performance review. We ask the SDT to provide clarification on this term. **Response:** The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. 2. We recommend that this design parameter be deleted. The intent appears to be an attempt to prevent the overexcitation of generators and, to a lesser degree, transformers. It would be very difficult for entities responsible for setting UFLS equipment to conceive of every imbalance condition and prevent the possibility of any localized generator overexcitation to occur. These design parameters would be more appropriately addressed in generation protection standards to assure that generating units that can have impact on the frequency of the bulk electric system utilize proper overexcitation protection. **Response:** It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.
American Transmission Company	No – Revise the design parameter as noted in the comments	With respect to the 25 percentage (Characteristic 4), refer to comments for Question 2. **Response:** See response to question 2. With respect to the 6-second or 1-minute V/Hz values (Characteristic 4.4), the basis for these values has not been well established. In addition, for some potential islands the appropriate volt/hertz limits might vary based on the composition of generators and transformers in the island. Absolute continent-wide values may not be appropriate. The Characteristics could require that the proper voltage/hertz limits be investigated and established for each potential island. The proper V/Hz limits should be re-examined and changed, if necessary, whenever a generator or transformer is added or removed for a potential island and may potentially change the limits. **Response:** The technical basis for the performance characteristics was developed through a review of relevant industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. The

Organization	Question 5	Question 5 Suggested Revisions:
		SDT included more details regarding the technical justification for the performance characteristics in the comment form background (including specific IEEE standards). The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. The SDT considers that continent-wide limits are appropriate and that the performance characteristic is achievable and a necessary requirement. Systems also need to perform acceptably for the benefit of the interconnection during events involving larger portions of an interconnection.
Indiana Municipal Power Agency	No – Revise the design parameter as noted in the comments	The term cumulatively is confusing. It either needs to be clarified or removed. A clarification is needed on the per unit Volts per Hz relay protection. Is this relay protecting a generator step up transformer or a transmission/distribution transformer? If it covers the generator step-up transformer, then this item should not be covered in NERC PRC-024 standard and not in a regional standard.
Response: The SDT clarifies that cumulative is per event simulated to verify that the performance characteristics are achieved by the UFLS program design. It is not the purpose of this standard to set generator volts per Hz requirements, but to ensure that the UFLS program operation does not result in generator volts per Hz tripping. The SDT modified Characteristic 4.4 (Requirement R6.4) to further specify the location (Requirements R6.4.1 and R6.4.2).		
Duke Energy	No – Delete the design parameter	Delete or at least revise this characteristic. Volts per hertz is not typically monitored or limited on the power system itself. It is more of a concern with regard to equipment protection. This would be a difficult requirement to measure with the current modeling software (and modeling tools). If voltage following an event is the concern, then a requirement for voltage (only) should be stated. The limits in item 4 above should be sufficient to define performance for frequency. It is not clear why a voltage requirement is required since the transmission system must be operated within stated voltage limits regardless. Again, if voltage or issues like tripping capacitors are a concern, it should be stated differently.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
Georgia Transmission Corporation	No – Delete the design parameter	This requirement would be better served in the generator protection standard.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to		

Organization	Question 5	Question 5 Suggested Revisions:
prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
Entergy	No – Delete the design parameter	We agree with and support the SERC comments.
Response: It is appropriate to include these performance characteristics in this project because over-voltages that are a direct result of UFLS operations must be considered when UFLS programs are designed and implemented. If design verification studies show an overvoltage problem, corrective measures must be applied to prevent equipment damage and further unnecessary outages or disturbances. It is not the purpose of this standard to set generator volts per Hz requirements but to ensure that the UFLS program operation does not result in generator volts per Hz tripping.		
PPL Generation	Yes	UFLS scheme should adhere to the IEEE standards for machines.
NPCC	Yes	
Buckeye Power, Inc.	Yes	
Northeast Utilities	Yes	
Independent Electricity System Operator	Yes	

6. If there are any other characteristics in the UFLS Regional Reliability Standard Characteristics document that you disagree with, please identify them here, and either identify that they should be deleted, or recommend an alternative.

Summary Consideration:

The Underfrequency Load Shedding drafting team reviewed responses to this question and based on these comments made several conforming and/or clarifying changes to the performance characteristics (now Requirements).

- Several comments raised concerns that the "UFLS Regional Reliability Standard Characteristics" did not assign responsibility for specific requirements, instead leaving this to the regional standard development process. The SDT believes these concerns are addressed by the SDT deciding to convert the "UFLS Regional Reliability Standard Characteristics" into a continent-wide standard, which required the SDT to assign responsibility for each requirement.

- Several comments suggested that the database should be updated annually for consistency with the annual certification of the amount of load expected to be shed, and to ensure up-to-date data is available for analysis of system events. Other comments questioned whether the certification of amount of load expected to be shed is a measure of compliance rather than a requirement. The SDT agreed with these comments and revised the performance characteristic (Requirement R8) to require annual updates of the database. The SDT also removed the annual certification noting this obligation is effectively addressed by Requirements R9 (annual database updates) and R10 (provide load tripping in accordance with the UFLS program design). The measures by which compliance with these Requirements will be assessed will be defined in the Measures section of the proposed standard.

- Several comments expressed concern with the requirement to identify potential islands, noting this may be difficult if not impossible in tightly integrated systems, that other means than system studies or actual system operations should be permitted and that additional specificity should be provided as to the criteria for identification of islands. The SDT acknowledges the potential difficulty in interconnected systems, but noted that it is important that potential islands studied are based on physical characteristics of the system. The SDT clarified requirements concerning identification of islands in Requirements R3, R4, and R5, including provisions to include "any other islands necessary to ensure that all portions of the region's Bulk Electric System are included in at least one island." The SDT declined to prescribe a methodology for identifying islands, noting that unique physical characteristics of regions across the continent resist attempts to define common criteria.

- One comment indicated that the term "cumulative" should be removed from the overexcitation limits. The SDT believes the cumulative reference in performance characteristic 4.4 (Requirement R6.4) is appropriate. If during an islanding event the excitation on a transformer or generator exceeded 1.18 pu for an extended period of time, it would be inappropriate to reset the time requirement following a brief decline below 1.18 pu. The SDT has revised performance characteristic 4 to clarify the intent that these cumulative limits apply for each simulated event; not cumulatively for all actual system events.

Several responses to this question reiterate concerns regarding coordination with the PRC-024 drafting team expressed in prior questions. The SDT clarifies that it coordinated with the PRC-024 Generator Verification Standard Drafting Team by providing the generator tripping curves to ensure that the performance characteristics do not conflict with the generator tripping curves.

Several responses to this question reiterate concerns regarding the 25% imbalance (at system peak) expressed in prior questions. The SDT clarifies that the 25% represents the imbalance between load and generation not the amount of load at system peak to be shed. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.

- Some responses to this question reiterate concerns expressed in prior questions that it is more appropriate for the Planning Coordinators associated with the individual regions/islands to determine appropriate design values, while still coordinating with other regions/islands. These responses indicated that most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. The SDT clarifies that the performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard.

Organization	Question 6	Question 6 Suggested Revisions:
NPCC	Disagree with one or more of the characteristics as noted in the comments	We believe that characteristic 8 in the "UFLS Regional Reliability Standard Characteristics" should require database updates on an annual basis consistent with the requirement for annual certification of the amount of load expected to be shed in characteristic 11. Up-to-date data is a necessary requirement for analysis of system events.
Response: The SDT has revised characteristic 8 (Requirement R9) to require entities to provide data annually in order to ensure that up-to-date data is available when required for post-event analysis of system disturbances. The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. This is intended to eliminate the confusion regarding characteristic 11.		
Grand River Dam Authority	Disagree with one or more of the characteristics as noted in the comments	In part 5 and 6 there is reference to PRC-024. I could not find this. Should it be mentioned now or should it wait until it is available?
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the references to PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 (Requirement R6) will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
ERCOT	Disagree with one or more of the characteristics as noted in the comments	Regarding characteristic item 6, we believe it should only apply for Generator(s) that a Region have exempted from being compliant with PRC-024 and hence are aware of the impact on the UFLS effectiveness. The current wording suggests that the UFLS should compensate for any Generator(s) whenever they are non-compliant with PRC-024. Suggested wording be changed to: Item 6. If the Region has exempted any generators from the underfrequency tripping requirements of PRC-024, the Standard shall specify how such generators shall avoid

Organization	Question 6	Question 6 Suggested Revisions:
		jeopardizing UFLS effectiveness, or how entities responsible for designing UFLS shall compensate for any such non-compliant generators in their area to avoid jeopardizing UFLS effectiveness. The Standard shall require modeling of these method(s) in the UFLS assessment specified in item 10 below to ensure UFLS effectiveness is not jeopardized.
Response: The intent of characteristic 6 is to prevent generators from jeopardizing performance of the UFLS programs during underfrequency events. This can only be accomplished if all generators, regardless of whether they are exempted from or non-compliant with PRC-024, are correctly modeled and accounted during the design of UFLS programs. The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
American Electric Power (AEP)	Disagree with one or more of the characteristics as noted in the comments	
Response: The SDT requires more information on your concern to be responsive to your concern.		
PPL Generation	Disagree with one or more of the characteristics as noted in the comments	Comments on Items 2 and 3: Determination of "potential islands" may be difficult, if not impossible, to determine for tightly integrated electrical systems. **Response:** The SDT agrees that identification of potential islands required in characteristic 2 may be difficult in tightly interconnected systems. However, it is important that the potential islands studied are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analyses used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5. Comments on Item 4: As noted earlier, the characteristics proposed should be used as a guideline with provisions for deviation from the guidelines if mis-coordination existing between the UFLS program and legacy generating facilities. **Response:** The SDT does not agree that the characteristics should be guidelines. Any miscoordination between the UFLS program and legacy generating facilities can be addressed through modifications to the UFLS programs such as percent load drop or frequency threshold settings. The SDT has limited the performance requirements to addressing those aspects of the design and implementation that have a direct impact on reliability. Common performance requirements such as those provided in performance characteristic 4 (Requirement R6) are necessary to achieve coordination of UFLS programs.

Organization	Question 6	Question 6 Suggested Revisions:
		Comments on Items 5 and 6: Because PRC-024 is not available for review; it is not clear how these characteristics are related to the standard and how the generator or the entity responsible for the UFLS program is to comply. **Response:** The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The combined performance requirement characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz, and at or below 61.8 Hz. Comments on Item 9: PPL Corporation suggests identifying a responsible entity very early in the standard drafting process. Failure to do so can make the standard approval process more difficult. Further, identifying the responsible entities early can help in ensuring a better product in the end. **Response:** The SDT agrees with the comment on characteristic 9. The SDT has assigned the Transmission Owner and Distribution Provider this responsibility in the proposed standard (Requirement R10). Comments on Item 10: PPL Corporation suggests that the Regional Entity be identified as the responsible party. This would be consistent with the SDT's recommendation that the Regional Entity author the standard. If the Regional Entity delegates the responsibility, a separate agreement should be developed to accomplish this rather than rather than including the agreement in the standard. **Response:** The SDT believes it is not necessary to assign responsibility for characteristic 10 to the Regional Entity in order to ensure system reliability. The SDT recognizes that NERC standards should not be applicable to Regional Entities and has assigned the Planning Coordinators within a region this responsibility in the proposed standard (Requirement R7). Comments on Item 11: The text of this characteristic is confusing. PPL Corporation suggests clarifying wording of the characteristic and clearly identify what is it be certified annually, i.e. amount (MW) of load to be shed if that is what the SDT intended. **Response:** The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. This is

Organization	Question 6	Question 6 Suggested Revisions:
		intended to eliminate the confusion regarding characteristic 11.
Southwest Power Pool	Disagree with one or more of the characteristics as noted in the comments	If PRC-024 hasn't been developed as an enforceable standard, how do we know that we can comply with Characteristics 5 and 6?
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Bandera Electric Cooperative	Disagree with one or more of the characteristics as noted in the comments	The TRE UFLS SDT believes that the requirement that frequency shall not remain below 59.5 Hz for greater than 30 seconds would require a change in the existing ERCOT UFLS program Step 1 (59.3 Hz). The halfway-point between 60 Hz (normal) and 58.5 Hz (10 second minimum) is 59.25 Hz. **Response:** Based on industry comments the SDT has revised the performance characteristics (Requirement R6.2) from 59.5Hz to 59.3 Hz for 30 seconds while still maintaining coordination with typical turbine operating characteristics. Frequency overshoot can be planned for by providing numerous steps of UFLS to avoid the overshoot. This should be fine for a gradual decay of frequency. However, during a large drop in frequency, all steps will operate simultaneously causing a possible overshoot. What can be done to reduce frequency at this point? **Response:** The SDT assumes that this condition would occur for a generation deficiency greater than 25%. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. For an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The SDT does not believe that the scenario mentioned by the commenter would lead to a frequency overshoot because the simultaneous operation of all steps would only occur if the imbalance exceeded the program capability. BEC voltage during and following UFLS operations shall be controlled not to exceed 1.18 for longer than 6 seconds cumulatively and 1.10 for longer than 1 minute cumulatively. Who should be responsible for non-compliance? Can this standard be enforced? **Response:** The SDT intended that performance characteristic 4 would apply only to the design of the UFLS

Organization	Question 6	Question 6 Suggested Revisions:
		program; not to post-event analysis of actual system events. As such the entity responsible for the design of the UFLS program will be responsible for demonstrating compliance with this performance characteristic under simulated conditions. The SDT believes this performance characteristic is enforceable as a UFLS program design requirement. The SDT has revised the language in characteristic 4 (Requirement R6) to better reflect our intent.
Midwest ISO	Disagree with one or more of the characteristics as noted in the comments	Item 5 references standard PRC-024. This standard should be vetted with these characteristics. Item 6 should not use the term non-compliant. A standard and its associated requirements are expected to be complied with. We suggest replacing item 6 with "The standard shall require taking into account the effect of generator underfrequency trip set points."
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Southern Company Services, Inc	Disagree with one or more of the characteristics as noted in the comments	Requirement 6 of the characteristics states the following: "The Standard shall specify how generators that are non-compliant with the PRC-024 underfrequency tripping requirement shall avoid jeopardizing UFLS effectiveness, or how entities responsible for designing UFLS shall compensate for any non-compliant generators in their area to avoid jeopardizing UFLS effectiveness. The Standard shall require modeling of these method(s) in the UFLS assessment specified in item 10 below to ensure UFLS effectiveness is not jeopardized." Is this requirement too open-ended for the responsible entity to have to "compensate" for non-compliant generators or does this approach give the responsible entity adequate flexibility to design mitigation plans into its methodologies? This seems to imply that (1) the non-compliant generators have already been identified and (2) that the responsible entity (not the non-compliant generator) shall be held responsible if mitigation plans are insufficient. We feel that Requirement 6 needs to avoid the use of the term "non-compliant" and instead focus on modeling actual generator trip points. We propose replacing Requirement 6 with the following: "The standard shall require taking into account the effect of generator underfrequency trip set points." The requirement, as originally written, is more appropriate in a generator protection standard. Non-compliance with PRC-024 should be addressed within PRC-024. Requirement 5 should be deleted since it is redundant with Requirement 4. Requirement 4.1, 4.2 and 4.3 should be re-worded to establish coordination with PRC-024 in each of the areas shown. As written, we feel there is a possibility of creating a double jeopardy situation with what may be written into the requirements of PRC-024.
Response: The SDT agrees. The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet		

Organization	Question 6	Question 6 Suggested Revisions:
characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
PJM	Disagree with one or more of the characteristics as noted in the comments	Delete Items 8 and 9 - should be handled in the Functional Model.
Response: The NERC Functional Model defines the reliability functions required for maintaining electric system reliability so that organizations involved in ensuring reliability can identify those functions they perform, and register with NERC as one or more of the Responsible Entities. The Functional Model is not intended to contain the level of specificity necessary to identify what entities are responsible for specific requirements of reliability standards. The SDT believes it is appropriate for standards to identify the entities responsible for providing data for database maintenance (characteristic 8, now Requirement R9) and owning, installing, and setting UFLS equipment (characteristic 9, now Requirement R10). The SDT has assigned the Transmission Owner and Distribution Provider these responsibilities in the proposed standard.		
Florida Reliability Coordinating Council	Disagree with one or more of the characteristics as noted in the comments	The characteristics should specify design criteria of the UFLS Programs and should not be confused with the actual system performance following an underfrequency condition. The UFLS Program should be developed to meet the design characteristics with the understanding that system performance will be dependent on the current system conditions and could potentially not meet the design characteristics of the program. Bullet No. 4 of the characteristics should read, "The Standard shall require that the UFLS Program be developed incorporating the following design characteristics?"
Response: The SDT intended that characteristic 4 (Requirement R6) would apply only to the design of the UFLS program; not to post-event analysis of actual system events. The SDT has revised the language in the proposed standard to better reflect our intent.		
Southern Company Services, Inc. – Trans	Disagree with one or more of the characteristics as noted in the comments	In addition to the above comments, requirement #6 need to avoid use of the term "non compliant" and instead focus on modeling actual generator trip points. Propose replacing # 6 with the following: "The standard shall require taking into account the effect of generator underfrequency trip set points." Requirement 5 should be deleted since it is redundant with Requirement 4.
Response: The SDT agrees. The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		

Organization	Question 6	Question 6 Suggested Revisions:
Northeast Utilities	Disagree with one or more of the characteristics as noted in the comments	Section 10.2 of the draft characteristics requires an assessment be conducted every 5 years. Based on experience, the schedule for a given analysis can drag beyond a deadline when there is difficulty in achieving convergence of study results, or modeling problems. There should be some accommodation in the Standard to account for these schedule overruns.
Response: The SDT recognizes the complexity involved with UFLS design. Developing the process for complying with performance characteristic 10.2 (Requirement R7) is left to the Planning Coordinators in each region. Re-assessment of the design, to be done at least every 5 years thereafter the original design, will be accomplished with the advantage of foreknowledge of the complexity and time involved in the initial UFLS program design. The Planning Coordinators must take this into account when developing their process for scheduling the UFLS design re-assessment.		
We Energies	Disagree with one or more of the characteristics as noted in the comments	Please see comments associated with question 5.
Response: Please see responses to comments associated with question 5.		
Florida Power & Light Co.	Disagree with one or more of the characteristics as noted in the comments	The design of a coordinated underfrequency load shedding program is primarily a planning activity that is based on analysis of potential islanding scenarios. With the exceptions noted above, it is reasonable to expect that a UFLS program's technical design parameters will meet the electrical design requirements identified in item four of the UFLS Regional Reliability Standard Characteristics for a load mismatch of 25%. Meeting these frequency and voltage design limits becomes increasingly difficult with higher load mismatch scenarios. The UFLS Regional Reliability Standard Characteristics as currently drafted implies the performance requirements should be applicable to both planned contingency scenarios and to actual performance during frequency excursions. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of at least 25% will meet the frequency and voltage performance requirements. Applying these requirements to actual disturbance events is inappropriate because of the large number of possible scenarios that may lead to frequency excursions. **Response:** The SDT agrees with the comment that meeting the proposed performance characteristics would become increasingly difficult for generation imbalances exceeding 25 percent. The SDT intended that compliance would not be required for an imbalance greater than 25% and has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/(load) of up to 25 percent within the identified island. For an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

Organization	Question 6	Question 6 Suggested Revisions:
		It is possible that an actual system islanding event occurs through a complex combination of multiple outages and adverse operating conditions that are impossible to predict. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of 25% will meet the frequency and voltage performance requirements. Accordingly, the words or actual system conditions should be removed from item 2 in the UFLS Regional Reliability Standard Characteristics. **Response:** The SDT intended that performance characteristic 2 would apply only to design of the UFLS program; not to post-event analysis of actual system events. However, it is important that the potential islands studied are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analyses used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5. Item 5 in the UFLS Regional Reliability Standard Characteristics as currently worded would prevent the use of additional layers of backup UFLS protection. The FRCC requires 9 UFLS steps be armed with a total of 56% of planned peak load. Some of these steps provide time delayed backup levels of protection in case frequency stabilizes at a level below 59.7 hertz or in case unplanned generator trips occur. In the event an island formed with a 50% load mismatch, it is likely frequency would go below 57.0 hertz and that generator tripping would occur before these time delayed backup steps would have a chance to operate. The words by requiring that UFLS programs complete execution before generators begin to trip on underfrequency should be removed from item 5 in the UFLS Regional Reliability Standard Characteristics. **Response:** As stated above, Regional Entities may, if they choose, develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedures for an imbalance exceeding 25%. The SDT has decided to revise and combine characteristics 5 and 6. In doing so, the words “by requiring that UFLS programs complete execution before generators begin to trip on underfrequency” have been removed from the combined characteristic (Requirement R7).
Exelon	Disagree with one or more of the characteristics as noted in the comments	Requirement 9 should specify the criteria used to determine an island subject to this standard. **Response:** Performance characteristic 2 (Requirement R5) does not provide criteria for determining potential islands; however, provides guidance that potential islands studied are based on physical characteristics of the system which can be identified through historical events or system studies, such as analysis used to identify coherent groups of generation, limited number of transmission connections, limited transfer capability, etc. Regions across the continent have unique physical characteristics that resist attempts to define common criteria to determine islands.

Organization	Question 6	Question 6 Suggested Revisions:
		Requirements 1 and 2 should specify which entities are responsible for determining what load is responsible for meeting the UFLS performance requirements of R4. Requirement 3 should specify which entities will ensure coordination across intra and inter-Regional boundaries. This should be consistent across the continent. **Response:** The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and has assigned responsibility for these requirements within the proposed standard. Requirement 5 and 6 should not address specific Standards, as it is unclear how this document could be updated if particular Standards were added, revised, or deleted which affect the Requirements included here. Requirement 6 is confusing - is non-compliance with portions of PRC-024 allowed through mechanisms alluded to here? **Response:** The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz. Requirements 7, 8, 9 and 10 should specify which entities are to maintain a data base, which entities are to maintain the data base and determine required parameters, which entities are responsible for owning, installing, and setting UFLS equipment, and which entities are responsible for performing UFLS assessments, respectively. **Response:** The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and has assigned responsibility for these requirements within the proposed standard.
Progress Energy Carolinas, Inc.	Disagree with one or more of the characteristics as noted in the comments	In addition to the above comments, NERC Characteristic #6 needs to avoid use of the term "non compliant" and instead focus on modeling actual generator trip points. Propose replacing Characteristic # 6 with the following: "The standard shall require taking into account the effect of generator underfrequency trip set points." Characteristic #5 should be deleted since implementation of Characteristic #4 should achieve this objective (i.e. Characteristic #5 is redundant).
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations		

Organization	Question 6	Question 6 Suggested Revisions:
performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Ameren	Disagree with one or more of the characteristics as noted in the comments	Regarding Item #7, we believe that the Regional Entity should maintain the database to provide uniformity and consistency. Regarding Item #9, the Standard which specifies who owns, install, or sets UFLS equipment should accommodate existing practices. For example, in some organizations, DP actually sheds the load to remedy a GO/TO system-wide event and the standard should ensure that these practices will be allowed to continue. Regarding Item #10, the regional entity should be responsible for performing the assessment or having an assessment performed.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and has assigned responsibility for characteristic 7 (Requirement R8) and characteristic 10 (Requirement R7) to the Planning Coordinators within each Region. The SDT recognizes that NERC standards should not be applicable to Regional Entities. The SDT agrees that existing practices should be accommodated where possible. The Planning Coordinators may define the UFLS program in a manner that accommodates existing practices with respect to shedding load. Regarding characteristic 9 (Requirement R10), Transmission Owners and Distribution Providers have been assigned responsibility in the continent-wide standard.		
Alliant Energy	Disagree with one or more of the characteristics as noted in the comments	The system performance (Requirement 4) prescribed by the SDT is based on typical values and their engineering judgment, and do not reflect how individual systems (or islands) were planned and designed (and what were/are deemed as acceptable risks). We believe it more appropriate for the Planning Coordinators associated with the individual regions/islands to decide what are the appropriate design values (for 4.1 to 4.4), while still coordinating with other regions/islands. We also believe most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. **Response:** The performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard. The MRO would ask that characteristics 5 and 6 remove the reference to PRC-024, but do agree with the need for coordination between UFLS and generation protection and expressing the characteristics 5 and 6 in more general terms. **Response:** The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below

Organization	Question 6	Question 6 Suggested Revisions:
		61.8 Hz.
E.ON U.S.	Disagree with one or more of the characteristics as noted in the comments	See Response to Question 9.
Response: Please see our response to your comment to Question 9.		
Manitoba Hydro	Disagree with one or more of the characteristics as noted in the comments	#8 requires entities to provide data at least every 5 years to support the UFLS database. #11 requires responsible entities to certify annually that the load it expects to shed will result in frequency excursions below the initializing set points of the regional UFLS standard. How can the responsible entity certify this, when the database, and therefore modeled conditions, may be 4 years out of date? Entities should be required to provide data annually to the UFLS, even if it is a "no change" ascertained.
Response: The SDT has revised characteristic 8 (Requirement R9) to require entities to provide data annually in order to ensure that up-to-date data is available when required for post-event analysis of system disturbances. The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. This is intended to eliminate the confusion regarding characteristic 11.		
PacifiCorp	Disagree with one or more of the characteristics as noted in the comments	Remove the requirement that the over excitation element be cumulative.
Response: The SDT believes the cumulative reference in performance characteristic 4.4 (Requirement R6.4) is appropriate. If during an islanding event the excitation on a transformer or generator exceeded 1.18 pu for an extended period of time, it would be inappropriate to reset the time requirement following a brief decline below 1.18 pu. The SDT has revised performance characteristic 4 to clarify the intent that these cumulative limits apply for each simulated event; not cumulatively for all actual system events.		
CenterPoint Energy	Disagree with one or more of the characteristics as noted in the comments	Characteristic Item 11 proposes that a UFLS regional standard include a requirement that owners of UFLS equipment must certify, on an annual basis, the amount of load it expects to shed in an underfrequency event. CenterPoint Energy concurs that some type of annual mechanism is warranted to "measure" whether the required load will be shed within a particular region, as UFLS is a critical safety net for the Bulk Power System - providing a last resort function. However, it would be expected that a UFLS regional standard would include the percentages of load to be shed as a Requirement. Therefore, CenterPoint Energy recommends that Characteristic Item 11 be deleted as a Requirement. CenterPoint Energy believes that a Requirement is not the appropriate vehicle to prescribe the type of compliance mechanism (e.g. certification, surveys, assessments), nor

Organization	Question 6	Question 6 Suggested Revisions:
		the frequency (e.g., annually) of the compliance check. These types of compliance items should be determined through the regional standard development process.
Response: The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. The SDT has revised characteristic 9 (Requirement R10) to specify that "Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which they operate." The measure by which compliance with the Requirement will be assessed will be defined in the Measures section of the proposed standard.		
FirstEnergy Corp.	Disagree with one or more of the characteristics as noted in the comments	Characteristics #5 and #6 - It is difficult to determine the acceptability of these characteristics since industry has not yet seen a draft of PRC-024 (Generator Performance During Frequency and Voltage Excursions). Completion of the development of these characteristics and coordination of these characteristics with the proposed requirements of PRC-024 cannot be finalized until the PRC-024 has been fully vetted through industry and approved by NERC and FERC.
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
American Transmission Company	Disagree with one or more of the characteristics as noted in the comments	The references to the PRC-024 standard should be removed and the desired characteristic restated in more general terms.
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Indiana Municipal Power Agency	Disagree with one or more of the characteristics as noted in the comments	A characteristic needs to be added to allow exemptions for equipment that might not be able to meet these under frequency characteristics or the Volts per Hz settings. Some equipment relay protection may not be able to be changed due to OEM limitations which need to be properly protected to prevent equipment damage. If an entity can provide the technical documentation to back up this OEM limitation and notifies the transmission planner, then an exemption should be allowed and not force an entity to be non-compliant.
Response: The proposed performance characteristics do not create any requirements that prohibit proper protection of equipment. The SDT does agree that		

Organization	Question 6	Question 6 Suggested Revisions:
equipment limitations should be addressed in any PRC standard that establishes protective relay setting requirements.		
Duke Energy	Disagree with one or more of the characteristics as noted in the comments	Disagreements are noted in the responses above. Additionally, -- Recommend deleting Requirement 5 since it is redundant with Requirement 4.-- Requirement 6 should avoid use of the term "non compliant". Compliance, and consequently non-compliance, should be handled in PRC-024 itself. If the goal is to verify the UFLS scheme while considering generation trip setpoints, then this requirement should focus on modeling the generation trip setpoints. Propose replacing Requirement 6 with the following: "The standard shall require generator underfrequency tripping be included in the UFLS assessment specified in item 10 below."-- **Response:** The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz. Requirement 2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording should be changed so that islands can be identified as appropriate and not just by system studies or actual system operations. For systems that have not experienced islanding events and where system studies have not shown islands, this would be difficult to meet. Recommend changing the requirement to read, "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." **Response:** Performance characteristic 2 (Requirement R5) has been revised so that islands may include “those islands selected by applying the criteria in Requirement 3, if any” (which considers historical events and system studies) and “any other islands necessary to ensure that all portions of the region’s Bulk Electric System are included in at least one island.”
Georgia Transmission Corporation	Disagree with one or more of the characteristics as noted in the comments	Requirement #6 needs to avoid the use of the term "non compliant" and instead focus on modeling actual generator trip points
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate		

Organization	Question 6	Question 6 Suggested Revisions:
with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Entergy	Disagree with one or more of the characteristics as noted in the comments	We agree with and support the SERC comments.
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Southwest Power Pool	Disagree with one or more of the characteristics as noted in the comments	Since PRC-024 is not a currently enforceable standard, we can not concur with Characteristics 5 and 6.
Response: The SDT has decided to revise and combine characteristics 5 and 6. In doing so, we have eliminated the reference to generators that are non-compliant with PRC-024. The SDT is coordinating with the Generator Verification SDT (Project 2007-09) to ensure that UFLS programs that meet characteristic 4 will coordinate with PRC-024, therefore eliminating the need for a direct reference to PRC-024. The combined characteristic (Requirement R7) now requires that dynamic simulations performed by each group of Planning Coordinators include modeling the trip settings of any generators that trip at or above 58.0 Hz and at or below 61.8 Hz.		
Transmission Reliability Program	Agree with all proposed characteristics	
Independent Electricity System Operator	Agree with all proposed characteristics	
Buckeye Power, Inc.	Agree with all proposed characteristics	
Louisiana Generqting, LLC	Agree with all proposed characteristics	
City Water, Light	Agree with all proposed	

Organization	Question 6	Question 6 Suggested Revisions:
& Power - Springfield, IL	characteristics	

7. The SDT proposes that the regional standards include the database requirements contained in existing Reliability Standard PRC-007. Do you agree that database requirements should be addressed within the Regional Standards?

Summary Consideration:

The responses to this question support the requirement for regional databases. The SDT has retained the regional aspect of the database requirement within the proposed continent-wide standard by assigning responsibility to the group of Planning Coordinators in each region to create and maintain a database containing relay information needed for assessments and event analysis (Requirement R8).

Several comments suggested that a common format for the database be established. The SDT believes that a variety of formats could serve reliability equally well and as such the SDT does not feel compelled to specify a format in the proposed continent-wide standard. The group of Planning Coordinators in each region has been assigned the responsibility for assessments of the UFLS program in the proposed continent-wide standard and is therefore best suited to identify the program database format.

Some comments suggested that the database should be updated annually, reiterating concerns expressed in responses to prior questions. The SDT agreed with these comments and revised the performance characteristic (Requirement R8) to require annual updates of the database.

One comment suggested including requirements for archiving the regional UFLS data. The SDT will address archiving requirements in the Data Retention section of the proposed standard.

Organization	Question 7	Question 7 Suggested Revisions:
Exelon	No	It would be helpful for inter-Regional coordination studies to have a common set of database requirements. Why not specify them here to ensure that this is standardized?
Response: The SDT expects that each regional UFLS database will need to contain the UFLS data items needed for UFLS assessments. While the approach proposed in the first posting would have allowed the regions to assign this responsibility, the SDT in the proposed standard has assigned the specification of database content to the Planning Coordinators in each region.		
E.ON U.S.	No	E.ON U.S. believes that database requirements should be established on a case-by-case basis. A database that tracks the dynamically changing system conditions under normal operation is not necessary. Only instances when an UF event occurs should be subject to a data retention requirement
Response: The SDT would like to clarify that the database contains UFLS program data; not event data.		
PPL Generation	Yes and No	PPL agrees that the database requirements should be addressed within the Regional Standard developed. However, the data requirements must be clearly identified. Further, the burden of providing such data in particular data formats (for study

Organization	Question 7	Question 7 Suggested Revisions:
		purposes) should not be delegated to the UFLS program owner - the Regional Entity performing the study should be responsible for data preparation and formatting.
Response: The SDT expects that each regional UFLS database will need to contain the UFLS data items needed for UFLS assessments. While the approach proposed in the first posting would have allowed the regions to assign this responsibility, the SDT in the proposed standard has assigned the specification of database content to the Planning Coordinators in each region. Any decisions on formatting requirements for data submittals by UFLS program owners are likewise reserved to the Planning Coordinators.		
Alliant Energy	Yes and No	The MRO agrees that any database requirements should be addressed within the Regional Standards. However, we hope that the database requirements among regions within the same Interconnection are the same. In addition, we would expect that the database would be required to be updated every year.
Response: The SDT expects that each regional UFLS database will need to contain the UFLS data items needed for UFLS assessments. While the approach proposed in the first posting would have allowed the regions to assign this responsibility, the SDT in the proposed standard has assigned the specification of database content to the Planning Coordinators in each region. A requirement for annual update of the regional UFLS databases has been added to the continent-wide standard (see Requirement R8).		
Bandera Electric Cooperative	Yes	The TRE UFLS SDT believes each regional UFLS program should include the requirement for archiving the region's UFLS data and that database should be available to entities within the region and should be part of the region's requirements constituting auditable compliance with the standard. The TRE UFLS SDT feels these databases are required to efficiently conduct the necessary studies. The regional standard should also clearly define the entity responsible/accountable for complying with the standard (equipment ownership, equipment maintenance, database maintenance, reporting, etc.) perhaps the RC or PA. Regardless of who is designated, that functional entity should be responsible for developing a database format/template to ensure UFLS data consistency and completeness as well as study efficiency.
Response: Under the continent-wide standard now being proposed, Planning Coordinators would be responsible for creating and maintaining a regional UFLS database. Archiving requirements will be covered in the Data Retention section of the proposed standard. The remaining points in this comment are consistent with the concept of regional standards in support of a continent-wide standard which the proposed continent-wide standard would allow.		
Southern Company Services, Inc	Yes	PRC-007 contains the specific requirement for ?documentation [to be provided for the] Regional Reliability Organization to maintain and update a UFLS program database.? PRC-006 specifies the design details to be addressed, such as frequency set points, time delays, etc. Some latitude is given to the regions in formulating the details of their UFLS programs and individual regional programs may differ to some extent. Therefore, in order to demonstrate that these region specific requirements are being meet, the database requirements will need to be included in the regional standards. Also, PRC-006 requires periodic dynamic simulations to assess the effectiveness of the UFLS program (ref. PRC-006 R1.4.2). Since different regions may have different requirements, the ability to obtain the necessary information to perform the required

Organization	Question 7	Question 7 Suggested Revisions:
		dynamic simulations (either on a regional basis or by individual entities), depends on being able to obtain the type of data that would reside in a UFLS program database. Including the database requirements within the Regional Standards will help ensure this is possible.
Response: Thank you for your support.		
SERC	Yes	PRC-007 contains the specific requirement for "documentation [to be provided for the] Regional Reliability Organization to maintain and update a UFLS program database." PRC-006 specifies the design details to be addressed, such as frequency setpoints, time delays, etc. Some latitude is given to the regions in formulating the details of their UFLS programs and individual regional programs may differ to some extent. Therefore, in order to demonstrate that these region specific requirements are being meet, the database requirements will need to be included in the regional standards. Also, PRC-006 requires periodic dynamic simulations to assess the effectiveness of the UFLS program (ref. PRC-006 R1.4.2). Since different regions may have different requirements, the ability to obtain the necessary information to perform the required dynamic simulations (either on a regional basis or by individual entities), depends on being able to obtain the type of data that would reside in a UFLS program database. Including the database requirements within the Regional Standards will help ensure this is possible.
Response: Thank you for your support.		
Buckeye Power, Inc.	Yes	Regional databases should have a common format and the database should have transparent coordination
Response: The SDT expects that each regional UFLS database will need to contain the UFLS data items needed for UFLS assessments. While the approach proposed in the first posting would have allowed the regions to assign this responsibility, the SDT in the proposed standard has assigned the specification of database content to the Planning Coordinators in each region. Any decisions on formatting requirements for data submittals by UFLS program owners are likewise reserved to the Planning Coordinators.		
Progress Energy Carolinas, Inc.	Yes	PRC-007 contains the specific requirement for "documentation [to be provided for the] Regional Reliability Organization to maintain and update a UFLS program database." PRC-006 specifies the design details to be addressed, such as frequency setpoints, time delays, etc. Some latitude is given to the regions in formulating the details of their UFLS programs and individual regional programs may differ to some extent. Therefore, in order to demonstrate that these region specific requirements are being meet, the database requirements will need to be included in the regional standards. Also, PRC-006 requires periodic dynamic simulations to assess the effectiveness of the UFLS program (ref. PRC-006 R1.4.2). Since different regions may have different requirements, the ability to obtain the necessary information to perform the required dynamic simulations (either on a regional basis or by individual entities), depends on being able to obtain the type of data that would reside in a UFLS program database. Including the database requirements within the Regional Standards will help

Organization	Question 7	Question 7 Suggested Revisions:
		ensure this is possible.
Response: Thank you for your support.		
American Transmission Company	Yes and No	ATC agrees that any database requirements should be addressed within the Regional Standards. However, we hope that the database requirements among regions within the same Interconnection are the same. In addition, we would expect that the database would be required to be updated every year.
Response: The SDT expects that each regional UFLS database will need to contain the UFLS data items needed for UFLS assessments. While the approach proposed in the first posting would have allowed the regions to assign this responsibility, the SDT in the proposed standard has assigned the specification of database content to the Planning Coordinators in each region. A requirement for annual update of the regional UFLS databases has been added to the continent-wide standard (see Requirement R8).		
Entergy	Yes	We agree with and support the SERC comments.
Response: Thank you for your support.		

8. Are you aware of any conflicts between the proposed regional standards and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

Summary Consideration:

The responses to this question did not identify any conflicts with regulatory functions, roles, orders, tariffs, rate schedules, legislative requirements, or agreements. Several comments suggested that state tariffs and OATT requirements need to be reviewed for potential conflicts, but no comments identified conflicts and it is not apparent to the SDT that any exist.

Some comments suggested potential confusion with existing programs or identifying responsibility for providing load shedding. The SDT believes these concerns are addressed in the continent-wide standard by assigning applicability to "Distribution Providers" and "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load." We believe this covers all load and eliminates potential confusion regarding Load Serving Entities.

One comment expressed concern with potential conflicts between PRC-006 and PRC-024 and recommended that development of PRC-006 be delayed until PRC-024 has been approved. The SDT believes that adequate coordination exists between the Generator Verification SDT developing PRC-024 and development of PRC-006. The SDT will continue to coordinate with the GVSDT and we believe it does not matter whether PRC-006 or PRC-024 is approved first as long as this coordination exists.

One comment expressed concern with potential conflicts with the draft Reliability First regional standard and legacy ECAR documents. The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.

Organization	Question 8	Question 8 Suggested Revisions:
Southern Company Services, Inc	Yes	We are concerned that the Under-Frequency Load Shedding characteristics are being developed and finalized prior to the development of the Generator Verification Standard - PRC-024. Since regional standards must coordinate with PRC-024 it is only prudent that the UFLS Drafting Team and the Regions have knowledge of the approved version of PRC-024 before the Drafting Team/Standards Committee requires regions to coordinate with the Generation Verification Standard. Also, some OATT requirements may need to be adjusted to be consistent with regional requirements.
Response: The technical basis for the UFLS performance characteristics was developed through a review of relevant industry standards that include voltage and frequency limits for major electrical equipment. The performance characteristics were selected to prevent equipment damage and to coordinate with generating unit protection. In addition, the SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team (GV SDT) by providing the underfrequency performance curve to ensure that the performance characteristics do not conflict with the generator off nominal frequency capability curve. The GV SDT has posted the generator off nominal frequency capability curve for industry comment and the UFLSDT will continue to coordinate with the GV SDT on this item. The UFLSDT believes it does not		

Organization	Question 8	Question 8 Suggested Revisions:
matter whether PRC-006 or PRC-024 is approved first as long as this coordination exists. Thank you for your input and caution. Individual drafting team members are not aware of any conflicts and based on numerous comments there are not any apparent conflicts.		
FirstEnergy Corp.	Yes	We feel that the design parameters specified in characteristic #4 conflicts with the draft RFC standard and legacy ECAR document.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure.		
Bandera Electric Cooperative	Yes and No	The TRE UFLS SDT believes there may potentially be a conflict. The ERCOT Power Region has customer choice of Retail Energy Providers (REP)/LSE. Although the standard appears to be written as permissible in not enforcing UFLS requirements on an LSE ("...and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization)...)", it might be construed that LSEs in ERCOT may be subject to the requirements under the standard as written. The TRE UFLS SDT also comments that the proposed standard does not address allocation to self-serve or large industrials. The TRE UFLS SDT believes that self-serve entities with load and generation connected to the grid should be addressed.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and has assigned applicability to "Distribution Providers" and "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load." We believe this covers all load and eliminates potential confusion regarding Load Serving Entities.		
PacifiCorp	Yes and No	Proposed regional standard should specify the responsibility for dropping loads that are not served by operator of the control area, such as power generated in another control area and then scheduled to serve distribution loads of another utility.
Response: The SDT has decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard and has assigned applicability to "Distribution Providers" and "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load." We believe this covers all load.		
Entergy	No	We agree with and support the SERC comments.
Response: Thank you for your input and caution. Individual drafting team members are not aware of any conflicts and based on numerous comments there are not any apparent conflicts.		

Organization	Question 8	Question 8 Suggested Revisions:
American Electric Power (AEP)	No	All state tariffs need to be reviewed for conflicts.
Response: Thank you for your input and caution. Individual drafting team members are not aware of any conflicts and based on numerous comments there are not any apparent conflicts.		
SERC	No	Some OATT requirements may need to be adjusted to be consistent with regional requirements.
Response: Thank you for your input and caution. Individual drafting team members are not aware of any conflicts and based on numerous comments there are not any apparent conflicts.		
Progress Energy Carolinas, Inc.	No	Some OATT requirements may need to be adjusted to be consistent with regional requirements.
Response: Thank you for your input and caution. Individual drafting team members are not aware of any conflicts and based on numerous comments there are not any apparent conflicts.		
City Water, Light & Power - Springfield, IL	No	
NPCC	No	
Grand River Dam Authority	No	
ERCOT	No	
Florida Power & Light	No	
Southwest Power Pool	No	
Louisiana Generqting, LLC	No	
Midwest ISO	No	
PJM	No	

Organization	Question 8	Question 8 Suggested Revisions:
Florida Reliability Coordinating Council	No	
Buckeye Power, Inc.	No	
Northeast Utilities	No	
We Energies	No	
Exelon	No	
Ameren	No	
Alliant Energy	No	
E.ON U.S.	No	
Manitoba Hydro	No	
Transmission Reliability Program	No	
Independent Electricity System Operator	No	
CenterPoint Energy	No	
American Transmission Company	No	
Duke Energy	No	
Georgia Transmission Corporation	No	
Southwest Power Pool	No	

9. Do you have any other questions or concerns with the proposed Under Frequency Load Shedding Regional Reliability Standard Characteristics that have not been addressed? If yes, please explain.

Summary Consideration:

In general the responses to this question reiterate concerns expressed in responses to prior questions. A few new issues were raised in responses to this question.

- One comment suggested the need to manage automatic load restoration in concert with the UFLS program. The SDT agrees and has added a requirement (R7.3) in the proposed continent-wide standard to require modeling of automatic load restoration in the five year assessments performed by the group of Planning Coordinators in each region.
- Some comments expressed concern that requiring "dynamic simulations" to verify the UFLS program design was overly prescriptive and could be revised to "analytical studies." The SDT believes it is not possible to verify the adequacy of the implementation of the regional UFLS program in achieving the performance characteristics without some sort of dynamic simulation and has decided to retain this level of specificity.
- Some comments suggested the need for the standard to recognize coordination requirements with other frequency responsive load programs. The SDT believes the Planning Coordinators need to consider any such programs to ensure their implementation coordinates with the performance characteristics contained in the proposed continent-wide standard.

The remaining responses to this question reiterate concerns expressed in responses to prior questions.

- Several comments expressed concern with the requirement to identify potential islands, noting this may be difficult if not impossible in tightly integrated systems, that other means than system studies or actual system operations should be permitted, and that additional specificity should be provided as to the criteria for identification of islands. The SDT acknowledges the potential difficulty in interconnected systems, but noted that it is important that potential islands studied are based on physical characteristics of the system. The SDT clarified requirements concerning identification of islands in Requirements R3, R4, and R5, including provisions to include "any other islands necessary to ensure that all portions of the region's system are included in at least one island." The SDT declined to prescribe a methodology for identifying islands, noting that unique physical characteristics of regions across the continent resist attempts to define common criteria.
- Several responses to this question reiterate concerns regarding the 25% imbalance (at system peak) expressed in prior questions. The SDT clarifies that the 25% represents the imbalance between load and generation not the amount of load at system peak to be shed. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island.
- Several responses to this question reiterate concerns regarding coordination with the PRC-024 standard drafting team expressed in prior questions. The SDT clarifies that it coordinated with the PRC-024 Generator Verification Standard Drafting Team by providing the generator tripping curves to ensure that the performance characteristics do not conflict with the generator tripping curves.
- Several comments raised concerns that the "UFLS Regional Reliability Standard Characteristics" did not assign responsibility for specific requirements, instead leaving this to the regional standard development process. The SDT believes these concerns are addressed by the

SDT deciding to convert the "UFLS Regional Reliability Standard Characteristics" into a continent-wide standard, which required the SDT to assign responsibility for each requirement.

- Several comments suggested that the database should be updated annually for consistency with the annual certification of the amount of load expected to be shed, and to ensure up-to-date data is available for analysis of system events. The SDT agreed with this comment and revised the performance characteristic (Requirement R8) to require annual updates of the database.
- Several comments suggested the need to clarify that compliance with the performance characteristics is demonstrated through design of the UFLS program rather than analysis of actual system events. The SDT agrees and has modified Requirement R6 in the proposed continent-wide standard to clarify this point.
- Some responses to this question indicate that it is more appropriate for the Planning Coordinators associated with the individual regions/islands to determine appropriate design values, while still coordinating with other regions/islands. These responses indicated that most if not all of the UFLS characteristics can be performed under the auspices of the Planning Coordinator function. The SDT clarifies that the performance characteristics are intended to ensure coordination among the programs the Planning Coordinators are required to design. We agree the UFLS design parameters can be devised by the Planning Coordinators and have assigned the Planning Coordinators this responsibility in the proposed standard.

Organization	Question 9	Question 9 Suggested Revisions:
NPCC	Yes	We believe that the phrase "meet the following performance characteristics for underfrequency conditions resulting from an imbalance between load and generation of at least 25 percent" could be interpreted to require meeting the performance requirements for all generation deficiencies between 25 percent and 100 percent, instead of the intended 0 percent to 25 percent. We recommend that this phrase be revised as "meet the following performance characteristics for underfrequency conditions resulting from all imbalances between load and generation between 0 and 25 percent." We understand the intent of using the words "at least" may have been to recognize that regions may base their program on deficiencies greater than 25 percent; however, it is not necessary to provide within these characteristics that regions may exceed these requirements. The related NERC "Implementation Plan for Underfrequency Load Shedding Regional Reliability Standard Characteristics" must consider that some regional programs may require modification in order to meet these requirements. Accordingly, a time based implementation schedule should be developed with input from the Regional Drafting Teams once more detail surrounding the individual Regional Standards are known.
Response: The SDT agrees and has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. The SDT agrees that there is a need for a time based implementation schedule. A future draft of the continent-wide standard will have an implementation plan that will consider modifications in order to meet these requirements.		

Organization	Question 9	Question 9 Suggested Revisions:
Florida Power & Light	Yes	This proposed standard references PRC -024 which is not yet an approved standard has not been released for comment, and does not seem to be available on the NERC website for review.
Response: The SDT has decided to revise and combine characteristics 5 and 6 (now covered by Requirement R7). In doing so, we have eliminated the references to PRC-024.		
PPL Generation	Yes	PPL agrees with the concept proposed by the SDT. However, unique problems can exist for generators not owned/operated by the host regulated TO/TSP. Such entities cannot make arrangements with "load" to mitigate a generator UF trip setting that may fall above the lowest setting of load UF trip settings. Generator manufacturers UF/OF trip points are extremely important and may be the independent variable in this equation. Generator owners/operators must respect the manufacturer's recommendations for the generator UF trip settings. Generator Owner/Operator shall provide the lowest plant underfrequency setting and basis for this setting to the TO/TSP and or BA/RC in order to ensure coordination with the load UF trip settings. It should also be understood that the lowest manufacturer setting of the generator may not be the driving UF setting that needs to be coordinated with the TO/TSP UFLS scheme of the transmission system. For example, a nuclear unit may have a reactor pump UF setting or the Reactor protective system both having UF relays that can result in a trip of the unit. In any event, the host TO/TOP/TSP/BA needs to coordinate the UFLS program settings with the generators most limiting UF trip settings. The Regional Entity, with input from TO/TSP and generators, should be responsible for ensuring such coordination exists.
Response: The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop. The SDT is proposing requiring the group of Planning Coordinators in each region to model the trip settings of generators that would trip at or above 58.0 Hz and at or below 61.8 Hz in Requirement R7. The Planning Coordinators would still need to show that their UFLS program design satisfies the performance characteristics in Requirement R6. Generator Owners have been removed from the applicability section of the proposed standard.		
Southwest Power Pool	Yes	Please include parameters that will address each region's approach conducting studies as requested in UFLS regional reliability standard characteristic. **Response:** The SDT needs more information regarding your concern to provide a response. > Is it acceptable for each region to assume that it is an island separate from neighboring region(s) when performing these studies even though during an actual event each region in Eastern Interconnect is interconnected to neighboring regions? **Response:** It is important that the potential islands studied are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analysis used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5.

Organization	Question 9	Question 9 Suggested Revisions:
		> There is a lot of wording in the questions in the Comment Form that states thing like: "must act", "does not exceed", "must arrest" This type of wording makes very rigid requirements and leaves little room for unplanned situations, mis-operations or acts of God. The wording needs to be modified to include the word "designed"; i.e. the system must be "designed" to act, must be "designed" to not exceed, and must be "designed" to arrest. This seems to apply we are making our best effort to meet the requirement, but not be penalized (found out-of-compliance) for something beyond our control. **Response:** This is the SDT's intent. The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6). > The frequency setting of first stage load shedding should be the same across the Eastern Interconnected system. **Response**: The SDT does not share this view. Existing UFLS programs in the Eastern Interconnection have various initial thresholds. As long as the performance characteristics are achieved, differences in first stage frequency trip points between regions are acceptable from a reliability standpoint. > The frequency set points mentioned in the document such as 58.0, 59.5, 61.0, etc. have been established decades ago by compiling the result of survey from different manufacturers in the IEEE publication. If a common set of frequency setpoints to be adopted for system wide usage, then, it is prudent that these settings be revisited. **Response:** These values have been selected to coordinate with the turbine capability of manufacturers reflected in PRC-024 generator off-nominal frequency performance requirements. The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.
Bandera Electric Cooperative	Yes	The TRE UFLS SDT believes the NERC standard should recognize the coordination requirements within and between the region's automatic UFLS and other frequency-related load shed programs. **Response:** The SDT disagrees that the proposed standard should recognize the coordination requirements within and between the region's automatic UFLS and other frequency related load shed programs. The Planning Coordinators will need to consider any such programs to ensure that implementation of these programs coordinate with the performance characteristics contained in the proposed continent-wide standard. The continent-wide performance criteria should require the regional standard clearly state the authority (i.e., RE, TP, TO, DSP, LSE, etc) that is responsible for the various requirements specified in the standard. **Response:** The SDT agrees and the applicability is now being identified in the proposed continent-wide standard.

Organization	Question 9	Question 9 Suggested Revisions:
		The TRE UFLS SDT also questions if the NERC performance criteria should set the values for frequency decline (etc) in the NERC characteristics? Could these be a required characteristic but set by the Region with proof of methodology? **Response:** The proposed UFLS program performance characteristics are reasonable means to set a coordinated level of performance for regional UFLS programs without restricting flexibility to specify UFLS program design parameters that best accommodate regional needs. The performance characteristics also ensure coordination with generator under-frequency trip points being developed for PRC-024 in Project 2007-09, Generator Verification. Also, what supporting documentation for restricting frequency overshoot to 61.0 Hz? We request that that NERC Generation Verification SDT state its reasoning/explanation. **Response:** Based on industry comment, the SDT revised this characteristic (Requirement R6.3) from 61 Hz to 61.8Hz for any duration. In addition, the SDT revised the characteristic (Requirement R6.3) from 60.5 Hz to 60.7 Hz for 30 seconds. These changes are intended to coordinate with generator limitations and are being coordinated with the Generator Verification SDT that is developing generator requirements (PRC-024). The TRE UFLS SDT also expresses its concern regarding compliance issues. For example, how will compliance be addressed for an entity which meets the region's UFLS program's design standards, yet the program does not yield the results expected under actual conditions? How will compliance be determined? **Response:** The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6).
Orrville Utilities	Yes	This standard should only apply to entities that have the capability of monitoring regional load imbalance. Many distribution providers (DPs) and load serving entities (LSEs) such as municipal utilities and REAs have no knowledge of their regional load status. If these DPs and LSEs are required to own and maintain any type of automated load shedding system, it will be triggered on the basis of frequency. This could possibly cause them to shed load under localized frequency excursions caused by severe weather, which is not required by this standard as written. If load imbalance will remain an integral part of this standard, then entities that do not have the capability to track regional load should be exempt from it. **Response:** The monitoring of real-time load imbalance is neither required nor applicable. The percent generation-load imbalance specified in item 4 (now Requirement R6) is intended to be used in simulation and serve as the basis for coming up with technical design parameters consisting of frequency trip points, step sizes, time delays, etc. All regional under-frequency load shedding (UFLS) programs must be triggered on frequency. Localized frequency excursions can occur only if a local area becomes disconnected (islanded) from the interconnection. If an island does occur and frequency falls below the trip points, the proposed

Organization	Question 9	Question 9 Suggested Revisions:
		standard requires that load shall be shed in accordance with the UFLS program's technical design parameters. An additional provision of this standard should be to allow DPs and LSEs that draw less than 100 megawatts (perhaps a larger number may be appropriate) from the BES to isolate themselves from the BES before a frequency excursion reaches 59.0 Hz, and/or before the duration of the excursion has reached 30 seconds. Some DPs and LSEs generate a portion of their load, and allowing them to isolate themselves early may enable them to maintain electric service to hospitals, municipal water systems, police and fire departments in the event that the BES cannot be saved from blackout. **Response:** Uncoordinated isolation of DPs or LSEs must be avoided. The Planning Coordinators will need to ensure that isolation of DPs or LSEs coordinate with the performance characteristics contained in the proposed continent-wide standard.
Midwest ISO	Yes	Item 10.1 should not require dynamic simulation but rather analytical studies.
Response: SDT believes it is not possible to demonstrate that the adequacy of the implementation of the regional UFLS program in achieving the performance characteristics can be verified without some sort of dynamic simulation.		
Southern Company Services, Inc	Yes	Requirement 2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording needs to be changed because it requires that islands shall be identified through system studies or actual system operations. Some systems may not have experienced any islanding events and system studies may not show any potential events. The wording should be changed so that "other islands deemed appropriate" can be used as the only islands, not just as additional islands. The sentence should read "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." **Response:** The SDT agrees that the wording in the proposed standard needs to be clarified. It is important that islands used for UFLS assessments are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analysis used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5. Other areas: 1) Requirement 6 (if not replaced as proposed in our response to Question 6) - "The Standard shall specify how generators that are non-compliant with the PRC-024 underfrequency tripping requirement shall avoid jeopardizing UFLS effectiveness, or how [[insert "the entity(s)"]] [[strike "entities"]] responsible for designing UFLS shall compensate?" **Response:** The SDT has decided to revise and combine characteristics 5 and 6 (now covered by Requirement R7). In doing so,

Organization	Question 9	Question 9 Suggested Revisions:
		we have eliminated the references to PRC-024. 2) At Requirements 10.2, 10.3 and 11 and observation was made that the use of "responsible entity" and "entity(s) responsible" seems inconsistent across the three characteristics. If the terminology is consistent, perhaps the drafting team would consider placing Item 11 immediately after Item 9. Both characteristics address "owning, installing, and setting UFLS equipment". **Response:** The applicability is now being identified in the proposed continent-wide standard. 3) Requirement 11 - "The Standard shall require that the entity(s) responsible for owning, installing, and setting UFLS equipment, in accordance with item 9 above, shall annually certify [[strike "that"]] the amount of load it expects to shed during a system event which results in system frequency excursions below the initializing set points of the regional UFLS standard." **Response:** The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. The SDT has revised characteristic 9 (Requirement R10) to specify that "Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which they operate.
Florida Reliability Coordinating Council	Yes	The design of a coordinated underfrequency load shedding program is primarily a planning activity that is based on analysis of potential islanding scenarios. With the exceptions noted above, it is reasonable to expect that a UFLS program's technical design parameters will meet the electrical design requirements identified in item four of the UFLS Regional Reliability Standard Characteristics, for a load mismatch of 25%. Meeting these frequency and voltage design limits becomes increasingly difficult with higher load mismatch scenarios. The UFLS Regional Reliability Standard Characteristics as currently drafted implies the performance requirements should be applicable to both planned contingency scenarios and to actual performance during frequency excursions. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of at least 25% will meet the frequency and voltage performance requirements. Applying these requirements to actual disturbance events is inappropriate because of the large number of possible scenarios that may lead to frequency excursions. It is possible that an actual system islanding event occurs through a complex combination of multiple outages and adverse operating conditions that are impossible to predict. The Regional Entity UFLS standards should require a simulation study of planned grid conditions that demonstrates that a potential island with a load mismatch of at least 25% will meet the frequency and voltage performance requirements. Accordingly, the words "or actual system operations" should be removed from item 2 in the UFLS Regional Reliability Standard Characteristics. **Response:** The comment reflects the SDT's intent. The SDT has modified the performance characteristic (now Requirement R6) to clarify an imbalance = (load — actual generation output)/ (load) of up to 25 percent within the identified island. Compliance with performance characteristics when the imbalance is

Organization	Question 9	Question 9 Suggested Revisions:
		greater than 25 % is not required by this standard. The design of the UFLS program, as demonstrated by simulation, must comply with the performance characteristics, not its performance during an event. The standard has been modified to further clarify this point (Requirement R6). Item 5 in the UFLS Regional Reliability Standard Characteristics as currently worded would prevent the use of additional layers of backup UFLS protection. The FRCC requires 9 UFLS steps be armed with a total of 56% of planned peak load. Some of these steps provide backup levels of protection in case unplanned generator trips occur. The words by requiring that UFLS programs complete execution before generators begin to trip on underfrequency should be removed from item 5 in the UFLS Regional Reliability Standard Characteristics. **Response:** The SDT believes that proposed performance characteristic values are achievable for generator deficits up to and including 25%. For an imbalance up to and including 25%, these performance characteristics must be met; however, for an imbalance exceeding 25%, the Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. The requirement for UFLS programs to complete execution before generators begin to trip has been removed. However, the Planning Coordinators would still need to show that their UFLS program design satisfies the performance characteristics in Requirement R6. The characteristics, as written, do not allow for a Regional Entity to set the design parameters of a UFLS Program. Since the FRCC has a single UFLS Program, to meet these characteristics the FRCC would be required to write a Regional Standard that would require compliance by the FRCC. The characteristics should be modified to state that these design parameters are required in a Regional Standard, if the Region has UFLS Programs designed by others. They should also state that a Regional Entity may have a UFLS Program and the program should be designed to meet these design parameters. **Response:** While the approach proposed in the first posting would have allowed the regional standard to assign the responsibility for setting the design parameters, the proposed continent-wide standard requires the Planning Coordinators within a region to define the amount of load shed required, how many blocks, at what frequency, etc.
SERC	Yes	Requirement 2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording needs to be changed because it requires that islands shall be identified through system studies or actual system operations. Some systems may not have experienced any islanding events and system studies may not show any potential events. The wording should be changed so that "other islands deemed appropriate" can be used as the only islands, not just as additional islands. The sentence should read "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS."

Organization	Question 9	Question 9 Suggested Revisions:
Response: The SDT agrees that the wording in the proposed standard needs to be clarified. It is important that islands used for UFLS assessments are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analysis used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5.		
Buckeye Power, Inc.	Yes	It is very important for Major Objective 1 from project 2007-01 to be achieved. If the standard increases costs significantly without providing a demonstrated reliability improvement it will be burdensome for some entities to bear without adding reliability value. A study should be performed to analyze the existing system requirements and to analyze where flexibility can increase or decrease value in the UFLS regional systems as part of the characteristics of the UFLS standard. The study can be used to aid in drafting the regional standard from a quantitative or technical perspective allowing for database coordination.
Response: The SDT's intent is to avoid imposing substantial costs with little or no incremental reliability benefit. The proposed continent-wide standard is intended to leverage existing practices while ensuring that these programs meet a continent wide level of reliability. Flexibility in choosing UFLS design parameters is maximized by specifying performance characteristics rather than continent-wide design parameters. There is a range of design parameters that regions may choose within that will allow UFLS programs to achieve the performance characteristics. A study by the Planning Coordinators within each region will be necessary to verify that the UFLS programs' technical design parameters achieve the performance characteristics.		
Northeast Utilities	Yes	Consider whether the document should ensure that responsible parties manage their automatic reclosing programs, along with the UFLS program.
Response: The SDT added a requirement to the proposed standard (Requirement R7.3) to include the modeling of automatic load restoration in the five year assessment.		
Progress Energy Carolinas, Inc.	Yes	Characteristic #2 states that "The Standard shall require that these islands be identified either through system studies or actual system operations, and may also include other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS." The wording needs to be changed because it requires that islands shall be identified through system studies or actual system operations. Some systems may not have experienced any islanding events and system studies may not show any potential events. The wording should be changed so that "other islands deemed appropriate" can be used as the only islands, not just as additional islands. The sentence should read "The Standard shall require that these islands be identified either through system studies, actual system operations, or other islands as deemed appropriate by the specified entity(s) as a design basis for UFLS."
Response: The SDT agrees that the wording in the proposed standard needs to be clarified. It is important that islands used for UFLS assessments are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analysis used to identify coherent groups of generation. The SDT has clarified requirements concerning identification of islands in Requirements R3, R4 and R5.		
Alliant Energy	Yes	In general we believe it should be left to the Regions to determine what the UFLS limits should be.

Organization	Question 9	Question 9 Suggested Revisions:
		As noted in this questionnaire, the SDT found that there are many ways to perform the UFLS function, depending on the characteristics of the Region. We believe that NERC should insure that there is a UFLS program in place in each region, that there is adequate technical justification for each region's UFLS program, the program is reviewed annually and the necessary changes made, etc. The Regions should be responsible to perform the necessary studies, determine the UFLS setpoints, undershoot/overshoot targets, etc. and enforce them. We believe that will deliver the most flexible and efficient method to implement UFLS. **Response:** Specifying performance characteristics is a reasonable means to set a minimum level of performance for regional UFLS programs without restricting flexibility to specify UFLS program design parameters that best accommodate regional needs. They establish common performance requirements to facilitate coordination between regions in an interconnection. They also ensure coordination with generator under-frequency trip points also being developed for PRC-024 in Project 2007-09, Generator Verification. Requirement 10.1: Change "through dynamic simulations" to "through analytical studies" because verification of meeting some performance requirements can be performed with other types of methods and simulations. **Response:** SDT believes it is not possible to demonstrate that the adequacy of the implementation of the regional UFLS program in achieving the performance characteristics can be verified without some sort of dynamic simulation. There needs to be an awareness that overvoltages will affect the performance of UFLS load shedding due to the increases in system load. One approach is to trip capacitors along with load (or take comparable actions) to try to keep voltages reasonable. Switchable high voltage line shunts and reactors also need to be considered where appropriate. Obviously, the goal would be to keep voltages close to initial levels as load is shed yet we recognize that despite best efforts, we will get considerable fluctuation in voltage as load is shed. **Response:** The SDT agrees on the need for this awareness and thanks the commenter.
E.ON U.S.	Yes	The design parameter is dynamic in nature. The Distribution provider at E.ON U.S. installs and maintains the UFLS hardware. E.ON U.S. can not ascertain at this time how the standard will impact the extent and location of individual relays. E.ON U.S. believes that its current installation is adequate to meet this design standard but if NERC believes that they do not, the financial impact of meeting NERC's requirements could be significant. E.ON U.S. questions whether the expense required to meet the standard, as proposed, is justified given the small likelihood that an UF event will occur. **Response:** Specifying performance characteristics is a reasonable means to set a minimum level of performance for regional UFLS programs without restricting flexibility to specify UFLS program design parameters that best accommodate regional needs. They

Organization	Question 9	Question 9 Suggested Revisions:
		establish common performance requirements to facilitate coordination between regions in an interconnection. Existing UFLS programs that meet these performance requirements will not require modification. The SDT agrees that underfrequency events are unlikely, but such events can adversely impact the Bulk Electric System if properly coordinated UFLS programs are not in place. Additionally, the standard is unclear as to how often the process must be updated (annually or other) E.ON U.S. requests that the standard be changed to require updates only when system conditions change to an extent that the existing UFLS processes must be altered. This would protect against doing unneeded updates for standardized time periods but would not eliminate that requirement if system conditions warrant changes in the UFLS processes. Making updates only when necessary as opposed to an administratively determined time frame will reduce costs which will benefit customers **Response:** Characteristic 10 (now Requirement R7) indicates that the Planning Coordinators in each region shall conduct a UFLS assessment every five years. Modifications to the UFLS program are required only when the assessment demonstrates that the performance requirements are not met; however, equipment settings and installations must conform to the program requirements.
Manitoba Hydro	Yes	Rather than trying to set a uniform performance criteria, the SDT should develop the characteristic and requirements that must be included in the regional and/or sub regional UFLS programs and let the regions and subregions to specify the performance criteria to meet the requirements. A key component is to coordinate UFLS with the generator protection for various conditions within the region. Therefore, it should be the responsibility of the regions and/or subregions to design their UFLS for their respective areas.
Response: Specifying performance characteristics is a reasonable means to set a minimum level of performance for regional UFLS programs without restricting flexibility to specify UFLS program design parameters that best accommodate regional needs. They establish common performance requirements to facilitate coordination between regions in an interconnection. They also ensure coordination with generator under-frequency trip points also being developed for PRC-024 in Project 2007-09, Generator Verification.		
PacifiCorp	Yes	UFLS Regional Reliability Standard Characteristics should be coordinated and modified if the Generator Verification Standard Drafting Team changes design parameters associated with generating unit protection as well as the generator tripping for both over and under frequency levels.
Response: The SDT is coordinating with Project 2007-09: Generator Verification (PRC-024) and will continue to do so as the projects develop.		
CenterPoint Energy	Yes	This draft contains numerous references to islands, presupposing regional and/or predetermined islanding, which may not be applicable for all interconnections, especially a single region interconnection.
Response: It is important that islands used for UFLS assessments are based on physical characteristics of the system which can be identified through analysis of actual system events or through system studies, such as analysis used to identify coherent groups of generation. The SDT has clarified requirements concerning		

Organization	Question 9	Question 9 Suggested Revisions:
identification of islands in Requirements R3, R4 and R5.		
FirstEnergy Corp.	Yes	FE has the following additional comments: 1. We believe that the characteristics should include shedding of load in minimum amount of steps as appropriate for the region. For example, for some regions it is necessary to shed load in a minimum of three steps to prevent overspeed tripping. **Response:** Historically, regions have taken different approaches in establishing detailed design parameters (including amount of load shedding steps) for the region's UFLS program and the proposed standard permits these different approaches to continue provided they meet the performance characteristics. 2. With regard to characteristic #9, it would be difficult for a standard to specify the entity that owns or physically installs UFLS equipment. We suggest this be re-worded as follows: "The standard shall specify the entity(s) responsible for implementing a UFLS program." **Response:** The applicability is now being identified in the proposed continent-wide standard. 3. The minimum UFLS characteristics should require coordination between regional entities to assure a wide-area view (i.e. the entire interconnection or wide view based on engineering studies) **Response:** The SDT believes that Requirement R4 address this concern. 4. Characteristic #11 requires the regional standard include requirements for the entity to "…annually certify the amount of load it plans to shed" We question why the requirement states this since this is more of an audit function; i.e. wouldn't the compliance monitor "certify" this? This characteristic should be removed and believe that the other characteristics cover this. **Response**: The SDT did not include characteristic 11 in the proposed standard. The proposed standard is no longer asking the responsible entity to annually certify the amount of load it expects to shed during a system event. The SDT believes that the obligation is covered by Requirement R9 and Requirement R10. The SDT has revised characteristic 9 (Requirement R10) to specify that "Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which they operate." The measure by which compliance with the Requirement will be assessed will be defined in the Measures section of the proposed standard. 5. We are not clear as to the intent or purpose of Characteristic #1. We recommend that this characteristic be removed since the regional standards will require each entity to set their UFLS equipment that they own and thereby would cover the necessary system boundaries. If there is some other intent to this characteristic, we ask that the SDT explain further and then clarify the wording. **Response:** Applicability is now being identified in the proposed continent-wide standard. The SDT has also clarified requirements

Organization	Question 9	Question 9 Suggested Revisions:
		concerning identification of islands in Requirements R3, R4 and R5.
American Transmission Company	Yes	Requirement 10.1: Change "through dynamic simulations" to "through analytical studies" because verification of meeting some performance requirements can be performed with other types of methods and simulations.
Response: SDT believes it is not possible to verify that the adequacy of the implementation of the regional UFLS program meets the performance characteristics without some sort of dynamic simulation.		
Entergy	Yes	We agree with and support the SERC comments.
Response: Please see response to SERC comments.		
Southwest Power Pool	Yes	We would propose that the following statement be included in the UFLS Regional Reliability Standard Characteristics - "Each LSE in a BA footprint is to coordinate their participation in a UFLS program with the host BA." **Response:** The proposed continent wide standard includes requirements for Planning Coordinators, Transmission Owners, and Distribution Providers. The SDT does not agree that the commenter's proposal is needed in the proposed continent-wide standard.
Georgia Transmission Corporation	Yes and No	Each region is different in load to generation mix and transmission configuration. I do not believe that one rule can apply globally to all regions. Only regional stability studies can determine acceptable load shed steps and needs.
Response: Specifying performance characteristics is a reasonable means to set a minimum level of performance for regional UFLS programs without restricting flexibility to specify UFLS program design parameters that best accommodate regional needs. They establish common performance requirements to facilitate coordination between regions in an interconnection. They also ensure coordination with generator under-frequency trip points also being developed for PRC-024 in Project 2007-09, Generator Verification.		
PJM	No	
We Energies	No	
Exelon	No	
Ameren	No	

Organization	Question 9	Question 9 Suggested Revisions:
Transmission Reliability Program	No	
Independent Electricity System Operator	No	
Duke Energy	No	
City Water, Light & Power - Springfield, IL	No	
Grand River Dam Authority	No	
ERCOT	No	
American Electric Power (AEP)	No	
Louisiana Generating, LLC	No	

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PRC-006, PRC-007, and PRC-009 Mapping to Proposed Continent-Wide Standard

PRC-006: Development and Documentation of Regional UFLS Programs

Requirement in the Existing PRC Standards	Location in UFLS Regional Reliability Standard Characteristics (1st Posting)	Location in Proposed Continent-Wide UFLS Standard (2nd Posting)	Needed for Reliability
R1: Each Regional Reliability Organization shall develop, coordinate, and document an UFLS program, which shall include the following:	UFLS Regional Reliability Standard Characteristics 1, 2, and 3.	Continent-wide Standard Requirements R1, R2, R3, R4, and R5.	Yes
R1.1: Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations.	UFLS Regional Reliability Standard Characteristic 3.	Continent-wide Standard Requirement R4.	Yes
R1.2: Design details shall include, but are not limited to: **R.1.2.1:** Frequency set points. **R.1.2.2:** Size of corresponding load shedding blocks (% of connected loads.) **R.1.2.3:** Intentional and total tripping time delays. **R.1.2.4:** Generation protection. **R.1.2.5:** Tie tripping schemes. **R.1.2.6:** Islanding schemes. **R.1.2.7:** Automatic load restoration schemes. **R.1.2.8:** Any other schemes that are part of or impact the UFLS programs.	These design details will be included in the Regional Standards, and will be established within each region to meet the common system performance standard defined by UFLS Regional Reliability Standard Characteristics 4 and 5.	Continent-wide Standard Requirements R6 and R7.1.	Yes

Requirement in the Existing PRC Standards	Location in UFLS Regional Reliability Standard Characteristics (1st Posting)	Location in Proposed Continent-Wide UFLS Standard (2nd Posting)	Needed for Reliability
R1.3: A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.	UFLS Regional Reliability Standard Characteristics 7 and 8.	Continent-wide Standard Requirements R8 and R9.	Yes
R1.4: Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to: **R1.4.1:** A review of the frequency set points and timing, and **R1.4.2:** Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation.	UFLS Regional Reliability Standard Characteristic 10.	Continent-wide Standard Requirement R7.	Yes
R2: The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).	UFLS Regional Reliability Standard Characteristics 7 and 8.	These existing requirements are covered in the ERO Rules of Procedures, Section 401: 3. Data Access — All bulk power system owners, operators, and users shall provide to NERC and the applicable regional entity such information as is necessary to monitor compliance with the reliability standards. NERC and the	No

Requirement in the Existing PRC Standards	Location in UFLS Regional Reliability Standard Characteristics (1st Posting)	Location in Proposed Continent-Wide UFLS Standard (2nd Posting)	Needed for Reliability
		applicable regional entity will define the data retention and reporting requirements in the reliability standards and compliance reporting procedures.	
R3: The Regional Reliability Organization shall provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days).	UFLS Regional Reliability Standard Characteristic 10.	These existing requirements are covered in the ERO Rules of Procedures, Section 401: 3. Data Access — All bulk power system owners, operators, and users shall provide to NERC and the applicable regional entity such information as is necessary to monitor compliance with the reliability standards. NERC and the applicable regional entity will define the data retention and reporting requirements in the reliability standards and compliance reporting procedures.	No

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PRC-007: Assuring Consistency with Regional UFLS Program Requirements

Requirement in the Existing PRC Standards	Location in UFLS Regional Reliability Standard Characteristics (1st Posting)	Location in Proposed Continent-Wide UFLS Standard (2nd Posting)	Needed for Reliability
R1: The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.	UFLS Regional Reliability Standard Characteristic 11.	Continent-wide Standard Requirements R9 and R10.	Yes
R2: The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.	UFLS Regional Reliability Standard Characteristics 7 and 8.	Continent-wide Standard Requirement R9.	Yes
R3: The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).	UFLS Regional Reliability Standard Characteristic 10.	Continent-wide Standard Requirement R9.	Yes

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PRC-009: UFLS Performance Following an Underfrequency Event

Requirement in the Existing PRC Standards	Location in UFLS Regional Reliability Standard Characteristics (1st Posting)	Location in Proposed Continent-Wide UFLS Standard (2nd Posting)	Needed for Reliability
R1: The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	Yes
R1.1: A description of the event including initiating conditions.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting	Yes

Requirement in the Existing PRC Standards	Location in UFLS Regional Reliability Standard Characteristics (1st Posting)	Location in Proposed Continent-Wide UFLS Standard (2nd Posting)	Needed for Reliability
	to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	
R1.2: A review of the UFLS set points and tripping times.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	Yes
R1.3: A simulation of the event.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting	Yes

Requirement in the Existing PRC Standards	Location in UFLS Regional Reliability Standard Characteristics (1st Posting)	Location in Proposed Continent-Wide UFLS Standard (2nd Posting)	Needed for Reliability
	to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	
R1.4: A summary of the findings.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	Yes
R2: The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system models and data	These existing requirements are covered in the ERO Rules of Procedures, Appendix 8, page 296: A NERC-level analysis will comprise (a) collecting pertinent event data; (b) constructing a detailed sequence of events leading to and triggering the disturbance; (c) assembling system	Yes

Requirement in the Existing PRC Standards	Location in UFLS Regional Reliability Standard Characteristics (1st Posting)	Location in Proposed Continent-Wide UFLS Standard (2nd Posting)	Needed for Reliability
	and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	models and data and conducting detailed system analysis to simulate pre- and post-event conditions; and (d) issuing findings, conclusions, and recommendations.	

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Unofficial Comment Form for the Second Draft of the Underfrequency Load Shedding Program Requirements — Project 2007-01

Please **DO NOT** use this form. **Please use the electronic comment form located at the link below** to submit comments on the proposed second draft of the Underfrequency Load Shedding Program Requirements developed by the standard drafting team for Project 2007-01 – Underfrequency Load Shedding. Comments must be submitted by **May 21, 2009**. If you have questions please contact Stephanie Monzon at stephanie.monzon@nerc.net or by telephone at 610-608-8084.

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Background Information

The major objectives of Project 2007-01 Underfrequency Load Shedding are to:

1) Ensure UFLS programs are developed that meet the requirements of the proposed continent wide standard to provide an appropriate level of reliability (not least common denominator).
2) Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.
3) Address the issues raised by FERC Order 693 and other applicable orders.
4) Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5) Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

The standard drafting team (SDT) for Project 2007-01 Underfrequency Load Shedding (UFLS) based its work on the existing NERC standards:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs,
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements, and
- PRC-009-0 — UFLS Performance Following an Underfrequency Event.

Project 2007-01 Under Frequency Load Shedding is one of four projects[1] identified in the Reliability Standards Development Plan 2008-2010 as requiring a set of Regional Standards to support a continent-wide standard.

In accordance with the associated SAR, a standard drafting team was appointed to draft the continent-wide UFLS standard with consideration of developing supporting regional standards. For the first posting the team recommended that, instead of developing a continent-wide standard, NERC issue a set of UFLS performance characteristics required in regional reliability standards for implementing automatic UFLS programs to arrest declining

[1] The other three projects were, Project 2007-05 Balancing Authority Controls; Project 2007-11 Disturbance Monitoring; and Project 2008-04 Protection Systems

Bulk Electric System frequency. The team posted the set of UFLS performance characteristics for comment and received valuable feedback. However, many comments expressed concern that a directive containing these performance characteristics was a new form of "requirement" and would not necessarily follow the NERC standards development process including future revisions to the performance characteristics with industry input.

The team recommended that NERC use its authority from section 312.2 of the Rules of Procedure to direct each Regional Entity to develop a regional UFLS reliability standard based on approved UFLS Regional Reliability Standard Characteristics. Section 312.2 of the Rules of Procedure of the North American Electric Reliability Corporation states:

> **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform reliability standards across North America, in some cases it may not be feasible to achieve a reliability objective with a reliability standard that is uniformly applicable across North America. In such cases, NERC may direct regional entities to develop regional reliability standards necessary to implement a NERC reliability standard. Such regional reliability standards that are developed pursuant to a direction by NERC shall be made part of the NERC reliability standards.

While the Rules of Procedure allow NERC to direct the development of Regional Reliability Standards, the regional reliability standards must be developed to implement a NERC reliability standard. The standard drafting team's initial proposed approach of establishing common system performance characteristics rather than prescribing a uniform design specification for all UFLS programs within a continent-wide standard recognizes that the objective of the UFLS programs is to arrest and recover frequency in islanded portions of an interconnection. In addition, UFLS programs with differing design specifications can be successfully coordinated if they are designed to achieve the same system performance characteristics, even across interconnected regions. Nevertheless, the initial approach taken by the drafting team is not achievable absent a continent wide standard.

Considering industry feedback and the intent of the Rules of Procedure regarding directing regional reliability standards the team evaluated many options that would preserve the existing regional entity expertise relative to defining credible islands within or between its region and neighboring regions and expertise in assessing islands within their regions based on electrically interconnected areas. The team also considered the role of the Planning Coordinators in their analysis as the functional entity most suitable to determine the UFLS program design given that the Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements.

After much deliberation, the team decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent wide standard that will follow the standards development process. The team acknowledges that this is a shift in approach but sees many benefits to proceeding with a continent-wide standard.

- While the majority of the comments indicated support for the creation of Regional Standards that determine the details of the UFLS programs the majority of the comments also generally supported the concept of applying common continent-wide characteristics. The original intent was for the Regional Standards to meet these common performance characteristics. The creation of a continent-wide standard does not deviate from this approach but rather eliminates the confusion caused with this new form of requirement that was intended to direct the Regions to create Regional Reliability Standards for UFLS that met the common performance characteristics.

- The creation of a continent-wide standard does not prohibit the creation of Regional Standards for UFLS. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as permitted by the NERC Rules of Procedure. This approach still allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.
- The team's original intent with the performance characteristics to ensure coordination among the programs is still being preserved by proposing a continent-wide standard. The team assigned the responsibility of designing the UFLS program to the Planning Coordinator (Requirement R2). The Planning Coordinators within a region will define the amount of load shed required, how many blocks, at what frequency, etc. (these specific requirements will not be contained in the proposed continent wide standard).

In the development of the proposed continent wide standard, the SDT recognized that UFLS programs typically have been developed within each Region by representatives from the vertically integrated utilities, Control Areas, power pools, etc. in that Region. The SDT initially proposed that all UFLS requirements be contained within regional UFLS standards to utilize specific expertise within the regions and recognize that UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics, even across interconnected regions. In developing the proposed continent wide standard the SDT wanted to preserve and leverage the expertise within the regions. Since requirements should only be assigned to users, owners and operators of the Bulk Electric System, the SDT considered that the most appropriate entity to develop the UFLS programs based on function are the Planning Coordinators.

The proposed standard requires that all Planning Coordinators within a Region work together as a group to develop the UFLS program for that Region that conforms to the performance characteristics contained in the proposed continent wide standard. As proposed, the continent wide standard does not specify "how" the regional programs are to be developed. For instance, Planning Coordinators may elect to use their Regional Standards Development process to develop the programs (but this is not required) or they may determine that their existing programs fully meet the requirements of this proposed continent wide standard.

In the proposed standard the SDT has assigned applicability to "groups" of Planning Coordinators rather than individual Planning Coordinators with the intention of ensuring coordination among the entities developing the UFLS programs within and across the Regions. The concept of "groups" of Planning Coordinators also is intended to replicate historical practice where groups of entities within Regions have formed for the purpose of developing coordinated underfrequency load shedding programs.

The following questions will assist the SDT in finalizing the development of the Under Frequency Load Shedding continent wide standard. For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position. To improve the Under Frequency Load Shedding continent wide standard, the SDT would appreciate responses to as many of these questions as you can answer.

Characteristics of UFLS Regional Reliability Standards

1. UFLS programs typically have been developed within each Region by representatives from the vertically integrated utilities, Control Areas, power pools, etc. in that Region. The SDT initially proposed that all UFLS requirements be contained within regional UFLS standards to utilize specific expertise within the regions and recognize that UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics, even across interconnected regions. However, based on the rationale contained in the background, the SDT has developed a continent wide standard consistent with the historical practice that promotes the utilization of previous experience and expertise. As proposed, the continent-wide standard requires that all Planning Coordinators within a Region work together as a group to develop the UFLS program for that Region that conforms to the performance characteristics.

a. Do you agree that creating a continent wide standard preserves the intent of utilizing specific expertise within the regions to develop UFLS programs that meet common performance characteristics?

☐ Yes

☐ No

Comments:

b. Do you agree that the SDT has assigned responsibility to the appropriate entity?

☐ Yes

☐ No

Comments:

2. The SDT has strived to draft the applicability in a manner that includes all load while avoiding assigning applicability to more than one entity for the same load. The Functional Model indicates the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. Considering the Functional Model definition of Distribution Providers please indicate whether you believe it is necessary to assign applicability to "Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of a Distribution Provider's load".

☐ Yes

☐ No

Comments:

3. The proposed continent-wide standard requires that Planning Coordinators model the trip settings of any generators that trip at or above 58.0 Hz (Requirement R8) when verifying through dynamic simulation that the UFLS program design is adequate to meet the continent-wide performance characteristics specified in Requirement R6.

Do you agree with this approach to ensure that effectiveness of the UFLS program is not jeopardized by units that trip at or above the minimum frequency (58.0 Hz) at which the UFLS program may arrest frequency decline?

☐ Yes

☐ No

Comments:

4. **The SDT added a requirement that requires the Planning Coordinators model, in the five year assessments, any automatic load restoration that is designed to assist in stabilizing system frequency (Requirement R9). The team decided to add this requirement as a result of a comment during the first posting. Do you agree that this requirement is necessary for reliability?**

☐ Yes

☐ No

Comments:

5. **The SDT added a requirement in the underfrequency load shedding performance characteristics that requires (in simulations) frequency to not remain below 58.2 Hz for greater than four seconds cumulatively per simulated event (Requirement R6.2). The SDT added this requirement to better coordinate with the Generator Verification Project (PRC-024) tripping curve. Do you agree with this additional requirement?**

☐ Yes

☐ No

Comments:

6. **In the first posting, the Characteristics of UFLS Regional Reliability Standards required that UFLS programs be designed to limit the potential for overexcitation (V/Hz) of power system equipment at all Bulk Electric System buses. Based on industry comments, the SDT has revised this requirement in the proposed continent-wide standard to apply only at generator buses and generator step-up transformer high-side buses associated with individual generating units greater than 20 MVA (gross nameplate rating) and generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) that are directly connected to the BES. The SDT believes this change better addresses the need to have UFLS programs designed to coordinate with protection that may trip generators during an underfrequency event. Do you agree with this change?**

☐ Yes

☐ No

Comments:

7. If you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict in the comments section.

Comments:

8. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard PRC-006-1.

Comments:

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on November 21, 2006.
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard and posts for comments on April 15, 2009.

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed standard (the first posting was proposed common continent-wide performance characteristics as a directive to the Regional Entities to develop regional standards) for a 30 day comment period, from April 21 – May 20, 2009.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments on the second posting and post revised standard for a 30 day comment period.	July 7, 2009
2. Respond to comments on the draft of the proposed standard and implementation plan.	September 14, 2009
3. Obtain the Standards Committee's approval to move the standard forward to balloting.	September 16, 2009
4. Post the standard and implementation plan for a 30-day pre-ballot review.	October 1, 2009
5. Conduct an initial ballot for ten days.	November 15, 2009
6. Respond to comments submitted with the initial ballot.	November 30, 2009
7. Conduct a recirculation ballot for ten days.	December 15, 2009
8. BOT adoption.	

A. Introduction

1. **Title:** Automatic Underfrequency Load Shedding
2. **Number:** PRC-006-01
3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events.
4. **Applicability:**
   - **4.1.** Planning Coordinators
   - **4.2.** Distribution Providers
   - **4.3.** Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load
5. **(Proposed) Effective Date:** TBD

B. Requirements

R1. Each Planning Coordinator shall join a group consisting of all the Planning Coordinators within the region for each of the regions in which it performs the Planning Coordinator function.

R2. Each group of Planning Coordinators shall design an underfrequency load shedding program for consistent application across the region.

R3. Each group of Planning Coordinators shall develop criteria, considering historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands.

R4. Each group of Planning Coordinators shall develop a procedure for coordinating with groups of Planning Coordinators in neighboring regions within an interconnection to identify and reach agreement on islands between its region and neighboring regions within the interconnection. The procedure shall identify how the neighboring entities will assist in the UFLS assessments and document concurrence of assessment results.

R5. Each group of Planning Coordinators shall identify an island(s) as a basis for designing a UFLS program. The identified island(s) shall include:

- Those islands selected by applying the criteria in Requirement R3, if any.
- Any portions of the BES that are designed to be detached from the interconnection (planned islands) as a result of the operation of a relay scheme.
- Interregional islands agreed on by the Planning Coordinators.
- Any other islands necessary to ensure that all portions of the region's BES are included in at least one island.

R6. Each group of Planning Coordinators shall specify the technical design parameters of the underfrequency load shedding program required to meet the following performance characteristics in simulations of underfrequency conditions resulting from an

imbalance scenario where an imbalance = [(load - actual generation output) / (load)] of up to 25 percent within the identified island(s):

R6.1. Arrest frequency decline at no less than 58.0 Hz.

R6.2. Frequency shall not remain below 58.2 Hz for greater than four seconds cumulatively per simulated event, and shall not remain below 58.5 Hz for greater than ten seconds cumulatively per simulated event, and shall not remain below 59.3 Hz for greater than 30 seconds, cumulatively per simulated event.

R6.3. Frequency overshoot resulting from operation of UFLS relays shall not exceed 61.8 Hz for any duration and shall not exceed 60.7 Hz for greater than 30 seconds, cumulatively per simulated event.

R6.4. Control voltage during and following UFLS operations such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than two seconds cumulatively per simulated event, and does not exceed 1.10 for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with any:

R6.4.1. Individual generating unit greater than 20 MVA (gross nameplate rating) and directly connected to the BES.

R6.4.2. Generating plant/facility greater than 75 MVA (gross aggregate nameplate rating) and directly connected to the BES.

R7. Each group of Planning Coordinators shall conduct a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R6. The simulation shall include;

R7.1. Modeling the trip settings of any generators that trip at or above 58.0 Hz.

R7.2. Modeling the trip settings of any generators that trip at or below 61.8 Hz.

R7.3. Modeling any automatic load restoration that is designed to assist in stabilizing frequency.

R8. Each group of Planning Coordinators shall create and annually maintain a UFLS database containing relay information provided by their Transmission Owners and Distribution Providers for use in UFLS assessments and event analyses.

R9. Each Transmission Owner and Distribution Provider shall provide data to its group of Planning Coordinators according to the schedule and format specified by the group of Planning Coordinators to support maintenance of the database.

R10. Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
April 21–May 21, 2009

Now available at:
http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Project Name:
2007-01 — Underfrequency Load Shedding

Due Date and Submittal Information:
The comment period is open **until 8 p.m. EDT on May 21, 2009**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Content for Comment Period:
The standard drafting team is seeking comments on the proposed second draft of the underfrequency load shedding program requirements, including a proposed continent-wide standard:

- PRC-006-1 — Automatic Underfrequency Load Shedding

Based on comments received during the first comment period, the team decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent-wide standard that will follow the standards development process. If the new standard is approved, the following standards will be retired:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements
- PRC-009-0 — UFLS Performance Following an Underfrequency Event

Other Materials Posted:

- A revised mapping document (PRC-006, PRC-007, and PRC-009 Mapping to Proposed Continent-Wide Standard)
- The drafting team's consideration of industry comments received during the first comment period

Project Background:
Major objectives:

1. Ensure UFLS programs are developed that meet the requirements of the proposed continent wide standard to provide an appropriate level of reliability (not least common denominator).
2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.
3. Address the issues raised by FERC Order 693 and other applicable orders.
4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

Further details are available on the project page:
http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Applicability of Standards in Project:

- Planning Coordinators
- Distribution Providers
- Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (46 Responses)
Name (28 Responses)
Organization (28 Responses)
Group Name (18 Responses)
Contact Organization (18 Responses)
Characteristics (0 Responses)
Question 1a (45 Responses)
Question 1a Comments (46 Responses)
Question 1b (43 Responses)
Question 1b Comments (46 Responses)
Question 2 (43 Responses)
Question 2 Comments (46 Responses)
Question 3 (42 Responses)
Question 3 Comments (46 Responses)
Question 4 (42 Responses)
Question 4 Comments (46 Responses)
Question 5 (39 Responses)
Question 5 Comments (46 Responses)
Question 6 (39 Responses)
Question 6 Comments (46 Responses)
Question 7 (0 Responses)
Question 7 Comments (46 Responses)
Question 8 (0 Responses)
Question 8 Comments (46 Responses)

Individual
Russell A. Noble
Cowlitz County PUD
Yes
Yes
I would defer to the opinion of the Planning Coordinators, but am wondering why the RC is not involved. As far as the TO and DP responsibility I see no problem as long as it is clear what data and load tripping is required.
Yes
Yes, but for a different reason: many times the TO will be the owner of the UFLS equipment (e.g. Bonneville Power Administration), not the DP. There are many DP's who do not own UFLS equipment and should not be forced in this position if there is a willing TO to take on the responsibility.
Yes
This seems fair to me. There is no mandate not to allow trip settings above 58 Hz, but there must be very good reasons for such settings, and that such settings will not require greater than necessary load shedding efforts to stabilize the BPS. DPs and LSEs are sensitive to reliable service to their customers. Unnecessary load shedding would add insult to injury.
Yes
You meant Requirment R7.3? This seems to be an excellent idea to me. Anything that both stabilizes the BPS and improves on customer service is a winner.
Yes
Yes
Past experience has proved from efforts to comply with other data request mandated standards a disconnect on what specific data needs to be on hand for proper modeling. Keep in mind that the DP usually does not have the expertise, including many TOs, on what data will be needed. I would suggest there be a requirement that the PC not only develop the data set required, but actively (not passively) communicate to its DPs and TOs what is required. Simply expecting entities to stumble around in a web site and find the requirements complicates compliance efforts. Please note that I am not an expert in UFLS schemes and offer my limited knowledge as a compliance and

distribution engineer. Thank you for the opportunity to join in this venue.
Individual
Edward C. Stein
self
Yes
Yes
Group
TRE UFLS Standard Drafting Team
Bandera Electric Cooperative
Yes
The Texas Regional Entity Underfrequency Load Shedding Standard Drafting Team (TRE UFLS SDT) is pleased to provide these comments. These comments reflect the consensus of this specific regional standard drafting team and do not reflect the position of the Texas Regional Entity or ERCOT. The TRE UFLS SDT agrees that the basic common characteristics associated with the proposed UFLS standard provides for an appropriate level of required coordination within and, where applicable, between regions.
Yes
The TRE UFLS SDT believes specifically that data collection and assessments are most effectively carried out at the regional level. However, it is important to note one issue that will have to be dealt with in the regional standard and/or programs is how to account for the small load-serving systems (e.g., less than 25 MW) that are not NERC-registered.
Yes
The TRE UFLS SDT believes the applicable entities provided for in the proposed standard are appropriate. However, the TRE UFLS SDT believes that the only group that may not be clearly understood to have assigned applicability are self-served customers that can shut down generation and pull from the grid without activating their own underfrequency load shedding. Assigning applicability to “Transmission Owners with end-use load” may make this clearer but we are not sure it is clear enough for self-served industrials. Additional specific wording to address this may be needed.
Yes
It would appear to be essential that the Planning Coordinators’ data base include trip settings and time delay to tripping for resources that trip above the 58.0 Hz point. The effective simulation and design of a regional UFLS plan must definitively show the targeted islanding of the region. By not including the modeling of the trip points and time delays for machines that trip above 58.0, Hz, the Planning Coordinator cannot ensure the simulation and plan for effective and survivable islands that can be forecasted to exist post separation. The time criteria in R6.2, particularly the first two cumulative steps, require the effective modeling of machines set to trip above 58.0 Hz.
Yes
The TRE UFLS SDT believes that successful deployment of a UFLS is dependent on two concepts. The first is automatic reaction of the UFLS when frequency triggers its response to dump load. The second is load shall not be brought back until the Reliability Coordinator instructs each entity to do so in whatever order is appropriate for adequate recovery. Therefore modeling of any applicable automatic load restoration should be included in a region’s UFLS program.
Yes
The TRE UFLS SDT agrees that the UFLS program should coordinate with the performance requirements of the Generation Verification Project (PRC-024-1). The requirement for not remaining below 58.2 Hz for greater than four seconds appears to be within the No Trip Zone area of the Off Normal Frequency Capability Curve in Attachment 1 of PRC-024-1.
Yes
The TRE UFLS SDT believes this change creates a clear definition for equipment at generator buses and step-up transformer high-side buses for which the standard applies. However, the NERC UFLS SDT may want to consider adapting the definition of applicable generating units to conform to NERC’s Compliance Registry Criteria (NERC Statement Compliance Registry Criteria Rev 5.0 (October 16, 2008) – www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0[1].pdf) for Generator Owner/Operator: - Individual generating unit greater than 20 MVA (gross nameplate rating) and is directly connected to the bulk power system; - Generating plant/facility greater than 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating. This change would bring consistency to the definition of applicable generating units and would ensure that there is no confusion for wind farms and other generating plants/facilities.
At this time, the TRE UFLS SDT does not believe this proposed standard conflicts with any regulatory function, rule,

order, tariff, rate schedule, legislative requirement, or other applicable standard of which the team members are aware.
The TRE UFLS SDT appreciates the opportunity to provide these comments and commends the NERC UFLS SDT for its efforts.
Individual
Harvie Beavers
Colmac Clarion
Yes
Yes
Yes
No
Some U/F setpoints currently in use above 58.0 Hz were mandated by Generator OEM vice Transmission Operator. All U/F setpoint 'mandates' should be made not to violate design setpoints for specific generators OEM requirements when conducting analysis of setpoints.
Yes
Yes
Agree that it is a reasonable setpoint for consistent evaluation/simulation; may not be reasonable as a 'limit' after evaluation is complete.
Yes
Be aware that some small generators (>20 MVA but <75 MVA with 'extended' tielines may have difficulty meeting this requirement with some 'older' voltage regulators and stepup transformer arrangements.
Requirement differ from some current contract requirements that were 'inclusive' of existing tieline standards when written.
Individual
Elvin Epting
City of Bedford
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Distribution providers with fewer than 10,000 meter should be exempted for the UFLS program because their ability to effect the stability of the electrical grid is minimal and the cost of installing and maintaining the system would excessive.
Individual
Ray Phillips
Alabama Municipal Electric Authority
Yes
Yes
Yes
Yes
No
If the automatic load was induced by inductors I would have voted yes because this is part of good planning. I voted "no" because there is no way to determine or predict that "all" of the load for a load restoration activity would be

"available" if the automatic load restoration was for user or customer load.
Yes
The SDT should consider changing the four seconds to six seconds because of the data scanning requirements of other generator functions such as automatic generation control.
Yes
The SDT should consider the potential discrepancy with the generator side and their desire to include automatic load reduction. I assume automati load reduction would not take place at a generator bus.
The SDT should re-look at the timing requirements (4 seconds)in this standard and the timing requirements (such as 6 seconds in the AGC requirement) of other standards.
In requirement 10, "R10. Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates.", it requires the Distribution Provider to provide load tripping. This seems to imply that the Distribution Provider would not be able to satisfy this obligation in aggregate from its Balancing Authority or Transmission Operator through its power supply contracts. The requiement to provide load tripping is especially troublesome for small entities that have only one feeder supplying the load of its end use customers. Additionally a small entity that is registered as a Distribution Provider that has less than 100 MWs of load will provide little help in affecting the frequency of the BES. The SDT should consider a class of Distribution Providers and not all Distribution Providers.
Individual
Karl Bryan
US Army Corps of Engineers
Yes
The continent wide standard establishes the performance characteristics that must be met and requiring the PCs within a Region to develop the specifics allows the implementation of the Rel Stndrd to also include local variances and has the added benefit of maintaining planning expertise.
Yes
Yes
No
Without actually testing the UFLS, how do you know that the simulation testing adequately represents real world events? There needs to be more concrete assurance or testing of the generation side to show that the unis will not trip off. I realize that this assurance should be covered under the MOD Reliability Standards, but I don't think it has been completely addressed.
Yes
Modeling automatic load restoration on a 5 year cycle should capture the changes/modifications that the individual Registered Entities have done to their system. Too often the minor tweaks to a system get lost in the cracks and the cumulative modifications do have an impact on system studies.
Yes
Yes
Group
Pepco Holdings, Inc - Affiliates
Pepco Holdings, Inc.
Yes
The PHI Affiliates agree that the Planning Coordinators have their own expertise and access to the expertise of the TOs and DPs in their area.
Yes
Yes
PHI agrees that including the Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load eliminates the ambiguity that could result if Transmission Owners were not included in the Applicability list.
Yes
Yes
Yes
Yes

Individual
Tom Nappi
NIPSCO
No
It really depends on how this is accomplished.
Yes
The planning groups yes
Yes
No
The existing trip points with out time delay is 58.2 - To protect against turbine blade damage. I believe any under frequency event that allows the frequency to get to 58 HZ is to late/ and to slow.
Yes
No
4 seconds is to long.
No
Since much of the future generation seems to be wind power- they should be included
Any standard neededs to be very general- should include the effect of load on frequency; Define what amount of load they require to trip; Include rate of frequency change protection. Only require planned load tripping; Actual load is much more difficult to predict on lower voltage circuits.
Individual
Kenneth D. Brown b/h Joseph Lalier, Design Engineer Electric Delivery Planning
Public Service Electric and Gas Company
Yes
The creation of a continent wide standard is acceptable as long as the responsibility for developing a UFLS program remains with the Planning Coordinators/Authorities in the Regions.
Yes
No
The Distribution Provider can in most cases identify all the load that is included in the UFLS Program.
No
No, however, while the effort to determine if the UFLS program is effective if generators trip at or above a minimum frequency, we are not sure that any simulations are accurate enough to validate this. Every event is different, but if it can be accurately modeled, then it is a good approach.
No
It would not seem practical to consider automatic load restoration as a method to stabilize a system.
Not aware of any conflicts.
Individual
Steve Alexanderson
Central Lincoln
Yes
No
"Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" TOs that meet the registry criteria for DP should be registered as such. If they don't meet the criteria, they are not required to have UFLS and this standard is not applicable to the small unregistered distribution system in question. Instead, I propose that TOs be included with no qualification, or a qualification that expresses the following situation: A DP and a TO may jointly decide the most effective location for UFLS may be on the TO's system, where it may be easier to reach the load shedding target. It would then be the TO that would be required to meet R9 and R10.
No
But please see Q1b comments.
Yes
Yes
Yes

Yes
Group
SPP System Protection and Control Working Group
Southwest Power Pool
Yes
Yes
No
For those transmission owners that have facilities that meet the NERC definition of Distribution Provider, they should be registered in the compliance registry as such.
No
What is the basis for 58.0 Hz? If the region's lowest UFLS setting is designed for 58.7 Hz, is 58.0 Hz requirement critical from the Regional UFLS program point of view?
Yes
We agree with this requirement but believe there should be more specific language on what schemes should be included in the study. There may also be automatic load restoration schemes that have an impact on stabilizing system frequency but was not installed with that intent. The study should also consider the effects of these automatic restoration schemes.
Yes
Yes
Please confirm whether this requirement is applicable for generating stations/ plants connected to BES above 100 kV.
None at this time.
None at this time.
Individual
Jonathan Appelbaum
Long island power Authority
Yes
Yes
No
Yes
Yes
Yes
Yes
Consider rewoeding R10 to better limit the Compliance aspect for the DP to implement setting UFLS relays based on the forecasted loads projected for the peak period. Suggest this R10 - The DP once per calendar year shall review the forecasted loads it is serving and provide for UFLS in accordance with the UFLS program designed by the group of planning Coordinators for each region in which it operates.
Group
Exelon
Exelon Transmission Operations and Planning
Yes
No
GOs should be included as applicable entities because they play an important role in matching load and generation in periods of frequency excursion. That being said, the standard should not require the installation of under frequency relays at generators that would remain on line beyond these minimum requirements.
Yes
Need to verify all end use load participates regardless of supply voltage level.
Yes

Yes

It should be clear only those restoration systems designed to stabilize system frequency should be included in the standard. Requirement 9 in the proposed standard does not appear to be related to automatic load restoration systems.

No

This should be left up to the regions. Load trip set points are left up to the Regions and thus so should generating unit settings. Unit coordination requirements should be part of the PRC standards (PRC-001 and PRC-024). This requirement leaves the responsibilities of attaining this goal ambiguous. It would not be appropriate to base compliance on an entity performing a study on the study outcome.

No

Don't agree with going into the generator over excitation equipment. This is an issue that is regional in nature and should be addressed at that level.

Not aware of any conflicts at this time.

There is a concern with high frequency requirements because they are not clear as to what should occur or how it should be mitigated. If island frequency is greater then 60.7 HZ for more than 30 seconds what type of action needs to occur? What is the technical justification for these levels? In the previous 'Characteristics' document the high voltage levels were different than the levels in this draft standard. Due to the inherent difficulty in accurately postulating load and generation islands, establishing frequency limits for such islands is even more difficult. There should be a criteria as to how the studies are done (including islanding criteria and size) if there are going to be bounds placed on the frequency result of the simulation. If the timing components (4,10,20 seconds) are removed, then regions should establish minimum generator tripping standards for load shedding. Unit tripping should be a balance between limiting cumulative damage while at the same time coordinating with load shedding levels in order to arrest frequency decline. Disagree with requirement 5. Criteria for island formation and the resulting requirements for mitigation should be included in a standard where affected parties may participate through the open and fair NERC process. There should not be some unspecified criteria left up to various entities with no oversight or standaridized development process. It would be very difficult if not impossible to determine how islands will be formed and where load will remain intact.

Group

Bonneville Power Administration

BPA Transmission Reliability Program

Yes

The continent-wide standard is a MINIMUM. Regions may still apply a higher standard.

Yes

BPA will have to have delegation agreements with DP's when BPA is covering their loads with BPA-UFLS relays or through other UFLS armed load in our BAA.

Yes

It addresses DSI and other large loads that are directly connected to the BES.

Yes

Yes

It addresses automatic load restoration for frequency over-shoot.

Yes

Yes

The Applicability should be Planning Coordinators and Balancing Authorities. BPA suggests that everywhere it currently states "Planning Coordinator" that it be changed to "Planning Coordinator/Balancing Authority". R3. - This needs to say why they are selecting portions of the BES that may form islands. The reason would be "that may form islands to simulate frequency performance and design the UFLS schemes." R5. Second bullet - This should include both "relay scheme or special protection system." Related to R9. - Each Generator Owner also needs to provide data for their under frequency trip settings, if they are within the band specified, 58.0 Hz to 61.8 Hz, since they also need to be considered in the simulations.

Group

Northeast Power Coordinating Council

Northeast Power Coordinating Council

Yes

No

We agree that the Planning Coordinator is the correct Functional Model entity based on having a wide-area view and the planning expertise to perform UFLS assessments. However, it is not clear to us whether applicability can be assigned to a "group of Planning Coordinators" as opposed to individual Planning Coordinators.

No

Based on the definition of Distribution Provider in the Functional Model we believe that the applicability should be limited to Distribution Providers. All load should be accounted for by a registered Distribution Provider. The standard

should not be written to correct for deficiencies resulting from incorrect registration of entities, and proper registration is vital to the reliability of the UFLS program.

Yes

Yes

We believe that any automatic action that impacts recovery and stabilization of frequency must be modeled.

Yes

We believe it is important to remove this apparent miscoordination between the generator tripping requirements in PRC-024 and the UFLS program performance requirements in PRC-006.

No

We agree with the intent of the change to focus the concern on buses where V/Hz protection may trip generators rather than broadly applying to all BES buses. However, reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage or generating unit/plant nameplate MVA. We recommend that R6.4 apply to all generator buses and generator step-up (GSU) high-side buses similar to R7.1 and R7.2 applying to all generators that trip above 58.0 Hz or below 61.8 Hz.

NPCC has previously commented that the objective to control frequency overshoot cannot be met through UFLS program design alone in the absence of adequate generating unit governing response. Our immediate concern has been addressed by increasing the maximum overshoot limit to 61.8 Hz and we support this modification to the performance requirements. However, we expect this concern will resurface if standards requiring minimum frequency response are not implemented and further declines in system frequency response are observed. NPCC recommends that NERC develop standards for unit governing response that are consistent with and support the reliability objectives of standards PRC-006 (UFLS) and PRC-024 (Generator Performance). NPCC also notes that it may not be possible for the Planning Coordinators to design a reliable UFLS program that will arrest and recover declining frequency if an excessive number of generators are exempted from meeting the underfrequency performance requirements in PRC-024. Hydro-Quebec TransEnergie has technical parameters that differ from those specified in Requirements R6 and R7. A Variance will be needed to address those specific concerns.

Individual

Rao Somayajula

ReliabilityFirst Corporation

Yes

Yes

Yes

Yes

Yes

Yes

Yes

SDT has to develop a mechanism to make sure all the loads are accounted for.

Individual

Ronnie Frizzell

Arkansas Electric Cooperative Corporation

Yes

No

I agree with the Planning Coordinator Group concept but this group should be required to solicit the input from other functional entities such as the GO, TO, TOP, DP, and LSE when developing the criteria and plans. These other entities will have valuable insight as to what should and should not be included in the UFlS programs and need to have a voice during the development of these programs. I would suggest adding the following sentence to R2 and R3 "The design(R2)/criteria(R3)shall be developed taking into consideration the input and feedback from the Generator Owners, Transmission Owners, Transmission Operators, Distribution Providers and Load Serving Entities to which the design/critria shall apply." While the Distribution Provider may own the equipment the LSE will play a valuable role in determining which equipment should be used to shed load. The LSE and not necessarily the DP has a better knowledge of the load makeup served by the DP's equipment and thus may be in a better position to identify the best location for UF relays. For example the LSE would know if a circuit has a critical load where the DP may or may not have this knowledge. Since load is what is being dropped, the LSE is the best one to make the determation of

which load is to be shed. The LSE may not need be an applicable entity but the UF programs and plans should not be developed without their input. It may be that the standard applicability needs to be expanded to these other entities by adding something to the effect of: GO, TO, TOP, DP, and LSE will participate in the development of the UFLS program and plans by providing input and feedback.

Yes

Yes

Yes

It stands to reason that any tripping or restoration schemes that are automatic should be modeled and included in the simulations.

R7.2 the wording "... trip at or below 61.8 Hz" implies that any generator with a trip setting below 61.8 must be modeled. If a generator has an UNDER-frequency trip setting below 58 Hz then it falls into this catagory. Was this the intent? If the intent was to capture those units with OVER-frequency trip setting above 61.8 Hz then the wording needs to be changed to "trip at or above 61.8Hz". The drafting team did a good job.

Group

System Protection & Control

Georgia Transmission Corporation

Yes

A continent wide standard will create desired system performance criteria, while allowing flexibility within the regions.

Yes

Yes

Yes

Yes

Yes

Yes

There needs to be clarification as to loads and generation in this standard. If the intent is for the System to be secure for loss of xx amount of generation at summer peak and at winter peak in the planning model then that should be stated. In short, there needs to be further clarification on the relationship in regards to compliance within the Planning Model and the actual System Loads and Generation. Some entities in some regions require compliance with load shed percentages “real time”, 24/7. Others, only for the summer peak, and others for both summer and winter peaks. While these questions relate to “measurements”, it would be beneficial to know beforehand the SDT’s thinking on these before implementation begins.

Individual

Greg Rowland

Duke Energy

No

R2 requires “consistent application across the region”. As long as R6 is met, there should be no requirement for all systems within the region to be consistent. This will create unnecessary work to redesign systems that could meet R6 just because they are not consistent with other systems in the region. Recommend deleting the words “consistent application across” from R2. This is similar to not requiring the regions to be consistent as long as R6 is met.

No

The proposed standard’s requirements R1-R8 are applicable to Planning Coordinator, which isn’t a registered function in NERC’s compliance registry. Without applicability to a registered entity such as the Planning Authority or Transmission Planner, there is no clear responsibility for compliance. Also it is unclear how compliance can reasonably be enforced when responsibility is shared by a group of entities. It is not clear how non-compliance with R6 is addressed given that all PCs in the region are combined by R1. Somehow, each PC must be allowed to demonstrate compliance to the standard independently so compliant PCs are not penalized along with the non-compliant one(s).

No

We agree this change better coordinates with PRC-024. If coordination with PRC-024 is the ultimate goal, it seems a

simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.) The 'stair step' created by the proposed method greatly reduces the area available above the PRC-024 limit.[SERC UVLS team see chart below] Even with the added requirement, the UFLS curve still does not coordinate with the PRC 024 curve at 59.5 Hz. If the 59.3 Hz proposed by PRC-006 is maintained, then it seems PRC-024 should be approximately 0.1 Hz lower, 59.2 Hz. Otherwise, the upper limit for PRC-006 must be increased to coordinate with the PRC-024 curve (e.g. increase by 0.3 Hz to 59.6 Hz). Similarly, the upper requirement does not coordinate with PRC-024 out in time.

--- Similar to the response for 5, the team should consider simplifying the requirements by stating points that are just an offset of the PRC-024 requirements. As noted in the webinar, the overfrequency points do not coordinate with the PRC-024 curve at 30 sec and also out in time. --- Seems problematic for a loosely organized "group of Planning Coordinators" to create and maintain a database. There are several practical and compliance issues with this. This should be assigned to an entity with clear responsibilities and processes to accomplish the task. Additionally, "annually" and "database" is unnecessarily restrictive given the study is only required on a 5 year basis and in light of existing data collection processes. Recommend revising R8 as follows: "Each group of Planning Coordinators shall compile/assemble information provided by their Transmission Owners and Distribution Providers for use in UFLS assessments and event analyses." --- R7.1 and 7.2 could have the effect of shifting the generator's burden of staying on line to the load customer who must be shed to account for the generator's less-than-expected frequency performance. --- R9 needs a minimum time allowed to respond. --- R10 should say "shall implement the UFLS program" rather than "shall provide load tripping in accordance with the UFLS program" because the phrase "provide load tripping" could be confusing.

Individual

Barry Francis

Basin Electric Power Cooperative

Yes

See my detailed discussion under item 8, in it's entirety, but especially my sections 3.5 and 3.6. I believe a continent wide standard may be possible if we adopt a completely different type of measure but we cannot be setting performance details up front before the study work has been performed. Different sizes of programs have different performance characteristics, so a single set of performance characteristics will not meet the needs of all parts of North America.

No

I do not know for sure if responsibilities are assigned to the appropriate entity, so I answered NO, when "I do not know" might have been more appropriate. To some degree, everyone needs to get involved at some level to ensure we have a loading shedding program in place to act as a saftey net. I am concerned that the transitions associated with "mandatory compliance" appears to actually be decreasing the level of coordination we have traditionally had. Good coordination is the key to ensuring reliability. Among other things, we need to keep the NERC regions involved in this process. They have the committee structure to facilitate coordination matters, and they can bring everyone together to jointly focus on the issues.

No

It seems OK to consider transmission owners with end-use load connected to their Facilities as Distribution Providers, but I can see complications. How does a transmission owner with a small amount of end-use load have enough load to work with to satisfy the load shedding program description? This implies they would have to coordinate with someone else. Taking this concept further, it seems like we need to ensure the right program is implemented in aggregate, but not worry too much about each responsible party meeting the exact program specification. We can take advantage of one party shedding a little too much at one stage and another shedding a little less to get the right fit in the end. This is sort of taking advantage of offsetting errors. This implies some type of group coordination based on geographic area is needed to ensure the collective load shedding need is fulfilled.

No

Some type of risk assesment is needed, but a dynamic simulation may not always be appropriate if there are other ways to get the answer we are looking for. This subject, and related topics, are addressed in the comprehensive discussion I included under item 8. Please consider all of my comments under item 8 to understand my concerns. First of all, in some instances a regional (or subregional) load shedding program sheds more than the required minimum of load. A consequence is the expected minimum transient frequency will probably be below 58 Hz, at least for some set of conditions, so we are going to interpret "58 Hz" as 58 Hz or the minimum expected transient frequency of the regional (or subregional) program. This revised definition is what we consider to be important. Some of the older wind generation will trip early due to inherent instability of that type of induction generation. This is not a planned activity, but it is still loss of additional generation. In MRO we felt the present magnitude of this impact was small (and unpredictable) and it could be included as part of the original assessment of the total load shedding requirement. (This will have to be reconsidered as additional wind generation is added.) MRO expects that newer wind generation and virtually all of the conventional generation will be able to accommodate the generation off-nominal frequency tripping time delay requirements proposed by MRO. As far as we are aware, it appears the sole exception are owners of one model of gas turbine who may want to trip instantly at frequencies such as 58.2 Hz rather than accept brief dips below 58.2 Hz. In WECC, owners of similar units managed to comply with the comparable WECC generation off-nominal frequency tripping time delay standard. We hope this will be how it plays out in MRO after owners of these types of gas turbines take a closer look and their options. MRO does not encourage the practice of premature tripping of generation but we made a provision in the MRO UFLS program definition to allow premature tripping on underfrequency provided it meets certain provisions. This provision also applies to small non-utility generation which might be on a feeder that is tripped with load. Basically we require a nearly identical size block of load to be shed at nearly the same time and location to compensate. Owners who wish to do this should have some responsibility to demonstrate they can satisfy this provision. The burden of proof should be on those who

want an exclusion. At this point we believe that the group of Planning Coordinators (or the applicable study group in general) should decide on the appropriate analysis method to review impacts. They can decide if such loss of additional generation is significant or not. If we are only dealing with one or two small units on a large system, then this hardly needs further study other than to demonstrate it is feasible to trip additional load at the time the generation trips. As far as assessments go, we feel there are various approaches that can be taken to do this type of risk assessment. As written, the implication is that a full transient stability program is needed to do this analysis. There are other equally valid analytical approaches, each with different strengths and weaknesses, and the group of Planning Coordinators should be allowed to use whatever tools they feel are most appropriate for quantifying this risk. There are even ways to assess the risk of having units trip off early that do not rely on simulations, but instead just quantify the additional overload burden this adds to the island. Let engineers figure out how to study the problems using whatever tools, methods, and calculations they feel are appropriate. However, as a general principle, we should try to prevent units from tripping off before the UFLS program plays out. Even more important, we should not allow any generation to trip via dedicated overfrequency relays (other than tripping actions directly or indirectly related to the inherent factory installed load rejection protection that we do not want to be messing with). The one exception would be when overfrequency tripping of generation is a planned activity that is a feature of the UFLS program used to rebalance load and generation.

Yes

Any automatic feature of the load shedding program should be modeled in the ULFS Program assessment.

No

Please provide the technical justification for this performance criteria. This subject, and related topics, are addressed in the comprehensive discussion I included under item 8. Please consider all of my comments to understand my concerns. We understand the SDT wants to ensure load shedding programs achieve quick frequency recovery and minimize underfrequency exposure. However we do not feel this requirement is the right way to go about that. This type of criteria is overly specific and should not be in the NERC standard. The recently developed MRO UFLS program which sheds 30% of system load appears to meet this criteria, but the Canadian portions of MRO which have higher load shedding requirements are unlikely meet this criteria. Aggressive load shedding programs in general will probably not satisfy this requirement. Frequency recovery, overall load shedding performance, and coordination with generation protection, should all be evaluated at the regional level by those who do the technical analysis of regional load shedding programs. In addition to study work, a lot of common sense needs to be applied. Several things need to be discussed to clarify our position. First of all, we do not agree with the direction taken in PRC-024 to define off-nominal frequency settings for generation. That should never have been included as part of PRC-024. No technical justification was ever provided for the generation protection frequency setpoints and time delays suggested in PRC-024, and those setpoints and delays do not necessarily reflect actual equipment capabilities. NERC should not be defining generation off-nominal frequency protection standards such as those in PRC-024 unless this is only intended to be a starting point that can be adjusted, as needed, based on results of actual study work. It takes study work to define the expected worst case frequency recovery times of the load shedding program and off-nominal frequency exposure is strongly affected by the size of the load shedding program. Setting specific off-nominal frequency limits/criteria up front effectively sets the limit on how much load can be shed and drives all load shedding programs to the lowest common denominator. Obviously that will reduce reliability. Programs which shed more than the minimum required load will inherently experience lower frequencies and spend more time below 58.2 Hz. We believe that load shedding program design should be based on achieving the quickest frequency recovery that is possible subject to satisfying all of the other conflicting design requirements and constraints, such as minimizing overfrequency problems, and in the end you are left with the engineering realities of what settings are needed on turbine/generator protection to achieve coordination. The folks who do the analysis at the Region level are in the best position to judge what is appropriate in the end. Final recommendations for turbine/generator protection will involve trade offs and compromises that have to be resolved by engineering judgment and a good deal of common sense. We would like to point out that the risk to generation is somewhat less than implied by the generation underfrequency protection time delay settings and that being too conservative on the generation protection side will be a risk to system reliability. Consider that if premature generation tripping occurs that we are likely to initiate cascading loss of generation and go black. (The real loss of life exposure to power plants might be the restoration process of a black start plan, a plan which usually calls for this underfrequency protection to be disabled up front so they can pick the pieces back up.) In the context of a load shedding event, the risk to units is based on actual off-nominal frequency exposure, which is inherently something of a probability density function. For any load shedding program there are going to be certain combinations of overload and modeling assumptions where UFLS programs tend to stall out or where frequency recovery is sluggish. Think of this as narrow windows of vulnerability. For the majority of the conditions modeled, the frequency recovery is much quicker. A well designed UFLS program which is designed to force frequency recovery back towards 60 Hz can actually act as the first line of defense for generation and this is how the new MRO program was designed. Even more troubling to MRO, and this should be equally troubling to all of the NERC Regions, are the very short time delays the PRC-024 has proposed at the higher frequencies (below 58.5 Hz for <= 10 seconds, below 59.3 Hz for <=30 seconds). In the MRO program design work, for the US portion of MRO where we have the smallest load shedding requirement, we spent approximately 8.7 seconds to 1.4 seconds below 58.5 Hz depending on what was assumed for governor response and other modeling details. The 10 second requirement for 58.5 Hz was just barely satisfied but keep in mind that we also want to set generation trip times so we have some comfortable margin between expected frequency recovery times and generation trip delays in case "real world" complications slow down frequency recovery. Likewise case work shows we will be below 59.3 Hz for 58.4 seconds to 42.5 seconds depending on governor action and other modeling assumptions. This is longer than the proposed 30 second limit. The final recommendation of the MRO program was to require generation protection to have a minimum of a 300 second delay for the frequency band between 59.0 Hz and 59.3 Hz (10 times the delay recommended in PRC-024), and a 45 minute delay for the band between 59.3 Hz and 59.5 Hz (270 times the delay recommended in PRC-024). Further, we recognize that programs which shed more than 30% of load will need to relax these settings and accept greater time delays. Keep in mind the MRO program was designed to work even if we get no net governor type of action as we use additional small blocks of load shed on delay to kick us towards 60 Hz if recovery is slow. We felt we got the quickest frequency recovery that was possible

subject to all the other constraints we had to deal with, like limiting overfrequency and achieving relay coordination. We factored in considerable uncertainly into the design, but what may happen in the real world when everything else is going wrong can be chaotic and cannot always be anticipated. All of us in the industry really need to consider that when deciding how to set generation off-nominal frequency protection. Units can accept considerable time at frequencies closer to 60 Hz, and can generally operate continuously at +/- .5 Hz off of 60 Hz. The time delay associated with the 59.3 Hz setting proposed in PRC-024 is only 30 seconds which is way shorter than actual equipment capability (based on a reasonable accelerated loss of life per event). The system should be capable of operating at 59.3 Hz in excess of 30 minutes. In real life you would never want to set generation protection with a 30 second delay at 59.3 Hz. That is bound to cause trouble. In real life, the unexpected is going to eventually happen and our "perfect program on paper" will get a reality check. If frequency stalls out around 59.3 Hz, the actual equipment capability allows enough time for system operators to take manual actions. The proposed time delay in PRC-024 is too small to allow manual actions. Some may think that with a perfect automatic UFLS program that we can design things so this will not happen. Wrong, things can always get worse, Murphy's Law applies. We recognize that even the best UFLS program can fail in real life as everything else goes wrong out on the system. All load shedding gives us is a good chance of survival, but we can never assure ourselves it will always work as desired in the face of the unexpected. We need to constantly anticipate what can go wrong and eliminate as much of this inherent risk as we can, but we can never provide a safety net that will work for all modes of system failure. Here is a real world example of how we could stall out at some frequency such as 59.3 Hz (or any other frequency below 60 Hz for that matter). When load shedding occurs, there is a chance the system may break up further as tie lines between remote generation and load centers become over taxed and the two systems may lose synchronism (this cannot always be anticipated up front). The result is that subislands form where one is now surplus in generation and one has too much load. The island which is surplus in generation is now at risk of losing generation on overspeed (probably due to internal problems at each plant, especially thermal plants, that lead to random tripping that is nearly impossible to quantify). Once generation trips the island will plunge into a 2nd round of underfrequency. Fortunately loss of the first unit might allow the others to survive (i.e. steam valves can open back up) so the final imbalance might still be manageable. However in this instance, the region has already used up part or all of the automatic load shedding capability. With luck this island will settle out at some frequency where operators will have enough time to manually drop load to force frequency recovery before generator underfrequency protection trips. Once generation underfrequency protection trips the first unit, the system will cascade and go black. To give enough time to do manual load shedding at this higher frequencies, you need to set long time delays on the frequencies closest to 60 Hz.

No

Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit. It also seems this only applies when frequency drops below 57.2 Hz. This is discussed further in my comprehensive discussion included in item 8. This requirement should not be included because this is not a major concern. Assuming we want to study this, we will find this cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation. The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document. During an under frequency event, generators should be working to pull voltages down anyway. Please see response to question 8 regarding overvoltages related to tripping load without tripping capacitors.

1.0 Introduction After reviewing PRC-006 and PRC-024, I have to conclude that both are unsound. The general approach of trying to define a performance envelope up front before tradeoffs can be evaluated in the design work is going to be a problem. These standards really do not encourage the right thing, which is to ensure we have the right UFLS program in place to meet the needs of a given area. The “measures” are inherently subjective, and really do not measure if we have created the right “safety net”. I go into considerable detail to explain my concerns, but basically in the design phase we need to make compromises between mutually exclusive objectives. Therefore we need to stay away from trying to micromanage the design process at the Standards level. Tradeoffs affecting performance will always be involved and I do not think the standard needs to get involved in exactly how we reach a conclusion about what needs to be done. I think the standard should just focus on making sure we put the plans into effect, and that we implement the load shedding program. We should leave all of the performance issues to a work group that does the actual design and analysis. This is basically operating study type of work to create a remedial action scheme which responds to abnormal system conditions. My conclusion is that we need a different type of “measure” for the UFLS standard and that the generation off-nominal frequency protection related criteria in PRC-024 should be eliminated completely and that it should not be part of any NERC standard. PRC-024 is trying to make the compromise about what is an acceptable tradeoff for setting generation off-nominal frequency protection before the required study work is even started. It makes more sense to have a “measure” for UFLS which focuses on fulfilling the various activities such as design, implementation, and review, as the end result is what is important to ensure reliability. I envision this would be more of a pass/fail, have you performed these activities or not, type of assessment. I know this is a controversial statement, but I believe the following discussion will explain how I arrived at this conclusion. 1.1 My UFLS background Before I comment on technical issues, I would like to provide background information. This is to explain why I hold such strong opinions on the subject of UFLS, and to show my involvement and commitment to developing appropriate regional UFLS programs. I hope this gives some credibility to my statements. I have a unique “hands on” work experience. This gives me considerable insight into this subject and a different perspective. I have about 20 years of experience with UFLS issues, have dug deep into the subject, have read all the technical materials I could find, and so forth. I spent several man years on this subject although my primary job function involves power system analysis, mostly operating studies (power flow and stability studies and so forth). My initial involvement in UFLS was an offshoot of disturbance analysis. This involvement with UFLS expanded into the area of assessing regional needs and in doing the technical work to develop a new UFLS program

from the ground up which better fit the needs of different geographic regions. This was the big picture type of work with lots of things to consider. My background which is relevant to this area of investigation includes: * 29 years of experience doing system studies (power flow, transient stability, operating study work, modeling issues, disturbance analysis, etc.) * From 1987 to 1990 worked almost full time on the Colorado/Wyoming Off-Nominal Frequency Program design and study report (a regional load shedding and generation off-nominal frequency protection coordination effort tailored to the needs of the area, and which coordinated the needs to two islands, one a subset of the other). I was chairman of one of two technical work groups created by the executive committee, and did a significant amount of the analytical work and report writing. * 1996-1997, I worked on the WSCC UFLS program design and study report as one of five authors. This program is presently the WECC program and was strongly influenced by how the Colorado/Wyoming program was developed. * 2001, I performed a review of the MAPP UFLS program on behalf of MAPP, and concluded that MAPP needed to develop a new UFLS program to address overfrequency and generation off-nominal frequency protection concerns. * 2006-2007, I was chairman of the MRO UFLS Task Force which designed a new UFLS program and generation off-nominal frequency protection requirement for MRO. This was basically the follow up to the MAPP work that stalled out in 2001. Implementation has been put on hold until the NERC UFLS standards writing process has concluded. * I have had the benefit of collaborating with many other engineers, of varied backgrounds, on the subject of UFLS. I have been exposed to many different aspects of the problem and to different viewpoints. My perspective is based on information I have gathered as it pertains to system planning and operation, relaying, control area type of issues, power plant issues, and so forth. I was once told that "sometimes things seem simple only because we don't usually have the time to learn the complexities". This is certainly true of UFLS issues. This standards drafting process has led to certain initial conclusions that set the direction of how the UFLS standard is being drafted. I have to point out that things are not nearly as simple as they may appear at first glance, and we are jumping to the wrong conclusions, and that is steering this process in the wrong direction. In order to best explain my concerns with how this UFLS standard is being written, I need to cover some of the basics to provide a context. 1.2 The big picture: what are we trying to accomplish by shedding load? The simple answer is we want to use load shedding as a safety net. The objective is to prevent a blackout following an islanding event that creates an imbalance between load and generation. We want the program to force quick frequency recovery so that we can better coordinate with generation off-nominal frequency needs. We want to make sure that our program has no fatal flaws that are going to make things worse, and hopefully we can try to make this program as robust and foolproof as possible. 1.3 Who should design UFLS? The design details need to be resolved through a technical study process involving individuals with the skills to do this type of analysis, or who are willing to spend considerable time to learn the skills. Historically this has been accomplished by forming appropriate study groups. Such groups usually include individuals with varied backgrounds which may be relevant to dealing with the different aspects of off-nominal frequency issues. The NERC regions have always had the organizational structure to bring all of these experts together, and I doubt the concept of having a group of Planning Coordinators will be as effective at getting the subject matter experts involved. 1.4 Analytical approaches and modeling limitations First of all, there is no perfect tool for studying load shedding and performance is highly subjective. The question is, what performance, and for what conditions and assumptions? We have to keep this in mind before jumping to conclusions about what kind of performance characteristic we can meet. Trying to establish the UFLS performance characteristic up front and then designing the rest of the UFLS program afterwards is equivalent to saying we know what our protection needs are and what the resulting system performance is going to look like before we do any kind of analysis at all. This is unrealistic. The one factor which is the most significant is the size of the UFLS program. Larger programs have inherently different performance characteristics than small programs. More compromises have to be accepted to make larger programs work. NERC Regions typically set a minimum criteria for load shedding, but higher levels are sometimes needed and are typically allowed. The amount of load presently being shed in different areas varies from about 25% to 60% or more. Modeling must involve some form of dynamic simulation which captures the salient features. Underfrequency relay application guides suggest use of a simple equivalent inertia model which captures frequency decay dynamics. I have found this approach extremely useful and insightful. This approach is good for rapid prototyping and generalizing trends, evaluating performance over a range of overloads, evaluating sensitivities, etc. The weakness of this approach is it does not include effects of voltage changes and usually ignores governor action (in MRO UFLS work, we added a governor model as part of the sensitivity work, but designed the program to work even if we get no net governor type of response to an underfrequency event). The “Equivalent Inertia” approach is essentially use of a one bus stability case with voltage held at unity, which models the inertial response of a full system. Full stability cases are more useful for looking at a very specific scenario (one overload level, a historical event, etc.). Stability cases are also useful in addressing voltage transients and identifying possible system break points. The usefulness of a full stability case for the study of load shedding is often overestimated. In reality, too much detail is not always helpful in sorting out the general trends. Stability cases give a very specific answer but can fail to give the needed insight about how things work “in general” and it can take significant time to modify cases so they are useful for this type of analysis. The level of modeling needed for typical transient stability studies is somewhat different than what might be needed for a load shedding study, so do not expect that stability cases will have all of the modeling details needed for load shedding studies. The user has to be aware of what each dynamic modeling approach represents, and what the modeling limitations are. Even full stability cases do not model some of the processes which have an effect on a load shedding event and consequently results have to be carefully interpreted (for example, stability cases do not model generating plant boiler dynamics and emergency overspeed controls which protect for full load rejection, but which operate on large partial overloads). The way islands are created in the simulation can affect results. For instance, opening all lines at the same instant to form an island is a typical modeling approach that has nothing to do with how islands really form. This approach to creating an island will affect the final result to some extent, but we generally have no better option. We also need to stop once and a while and consider the real world issues to try and make things as fail safe as possible. There is more to UFLS design than just running studies. The point is that study work results are inherently approximate, and much more subjective than most realize. Simulations need to be interpreted with a good deal of common sense and a good understanding of system dynamics, and a clear idea of what all the qualifying simulation assumptions are. Hopefully this standard will stay away from prescribing any particular modeling or analytical approach. Let planners use the engineering tools they have as they see fit, and let them decide on the tradeoffs we have to accept to make this work. 1.5 UFLS design work, conflicting requirements, and

uncertainty UFLS program design and performance details can only be worked out through a systematic study work process that considers all of the relevant details, the conflicting requirements, and as much of the inherent uncertainty involved as is possible to consider. Despite the complexity, I believe we can design a good UFLS program for a given region if we are systematic and try to deal with all the issues as best as possible by applying good engineering methods and good judgment. Once we lay out all the details, we have an optimization problem, and have to consider the options available and the tradeoffs. Some of the final program details will probably end up being decided according to a judgment call. However, I do not believe that we can set performance standards first and then expect the engineers to magically make this work. Almost everything to do with UFLS has to be based upon study work and must have a solid technical justification. The design goal is to develop an UFLS program which has a high probability of preventing system collapse following an islanding event. This sounds simple so far, but a little investigation will show the problem we are trying to deal with is complex and poorly defined. We are guessing at what might happen and are trying to hedge our bets in the face of considerable uncertainty. The deeper the investigation goes, the more we become aware of the conflicting requirements. For instance, the things we need to do to limit the minimum frequency, to limit the maximum frequency, to ensure good relay coordination, and to maximize the size of the UFLS program all conflict with each other…to solve one problem we impact a different objective. Many factors which affect real world performance are outside of the control of the parties doing load shedding. These factors are: dynamic characteristics of load, system energy stored in rotating generation via the flywheel effect (this is the inertia, and it relates to dispatch), units which are unresponsive to governor action, boiler dynamics, power-load controllers which can over power governors and force units back to the original schedule, gas turbines which inherently drop power as frequency drops, wind generation which essentially provides no inertia and is highly unpredictable, unexpected random events, etc. To complicate the analysis, different parts of North America will have to address factors that are unique to their own local areas. We want to keep “real world” complications in mind as we do our studies, and it is even reasonable to anticipate what system operators will have to do next if load shedding fails to work as desired. Historical events show this happens, and if we are lucky frequencies will stall out close enough to 60 Hz that operator action can be initiated to restore frequency (this has implications concerning why it is a really bad idea to set generation protection time delays too short for frequencies between 59 Hz and 61 Hz). Also consider that we are just making educated guesses about what islands may form in real life. Some islands are easy to identify and predictable, but that is not always the case. Major breakups seem to occur following a sequence of events which are far beyond anything covered by typical criteria, and these events are usually nothing we would have ever dreamed up. Often the final island is not what we anticipated. At this point let’s assume we know what our island should be, what the maximum overload for this island will be, and that we have some idea of general performance objectives. As we go into study mode we find that many of the factors which affect results are difficult to pin down. This includes the assumptions used for load damping, governor response, and the energy stored in rotating units (the inertia). The term “typical data” reflects a rather wide range of these parameters. In developing the MRO program we dealt with this uncertainty by using the simplified equivalent inertia model and then varying all of these parameters over a fairly wide range as we also considered a range of potential overloads. This is much more than is typically done, and this type of sensitivity analysis would have been extremely difficult, if not impossible, to perform with a full stability case. In the design phase we want to work though all of the interrelated issues, such as achieving coordination with generation off-nominal frequency protection. To do this right, we have to design a load shedding program which gives the best frequency recovery (subject to all the other constraints), and then see how much time is spent below 60 Hz in various frequency bands so that we can propose generation protection settings with delays with some margin over our worst case frequency recovery times. We also need to know something about actual generation off-nominal frequency capabilities to further judge the appropriateness of the suggested protection settings. We want to make sure this safety net is well designed and that it has no obvious flaws. Preferably, we want to anticipate what could go wrong so that we can try to avoid as many problems as possible and alter the design accordingly. Then work has to iterate towards a best compromise solution. 2.0 Critique of PRC-006 Although the intent of this write up is to discuss PRC-006, I also have to discuss PRC-024 in some detail since both standards go hand in hand. Load shedding and generation protection are interrelated. Both parts have to be addressed together in any discussion of UFLS issues. It is unfortunate the standards drafting teams broke things down into two different standards like this. Generation off-nominal frequency protection is inherently part of UFLS programs, and has to be assessed in this context. 2.1 UFLS standards need to be technically sound. I empathize with the standards drafting team and know the difficulty of their task better than most. However, I am not satisfied with the NERC UFLS standard PRC-006 or the generation protection settings suggested in PRC-024. I find this new PRC-006 UFLS standard and the companion PRC-024 generator off-nominal frequency standard to be unsound. These standards are circumventing the needed analytical process and are drawing conclusions about what is appropriate before the study work is performed. These standards provide no technical justification for the proposed measures. As written, these standards will encourage smaller load shedding programs, and if that happens, the result will be that portions of the grid will have less of a safety net to rely upon when extreme events occur. 2.2 There is no requirement to assess load shedding needs My observation is that a minimum load shedding requirement of 25% to 30% of system load will serve the needs of most of the system. That is my personal judgment, based on previous study work experience. I also know we can design fairly well behaved programs which shed 30% of load, and my personal bias is to shed more than to shed less. However the 25% load shedding used in the East was based on the same type of analytical process as I would go through, and they felt this level was a better fit for the tradeoffs involved. UFLS design involves these types of judgment calls. However, it seems odd that this standard does not require any kind of assessment to define the size of the imbalance we may have to deal with. This means we are not requiring anyone to know their actual load shedding needs. Perhaps that is implied by having “groups” do the UFLS study work. The load shedding needs are the first thing I would want to know, and to get at this information we have to evaluate possible system breakup patterns and possible load and generation scenarios to see what the imbalance might be. The purpose of such a review would be to see how much coverage the 25% load shedding requirement gives, and to estimate what might be a more appropriate load shedding target level. This type of analysis does not have to be perfect; we just need to know general magnitudes and make sure the involved parties feel their own needs are being satisfied. I use the phrase “target level” in the sense that once study work is performed we may have to consider a different size load shedding program to achieve over all coordination requirements. Everything is a series of tradeoffs. If we set performance criteria too tight, we could easily find that all

we have left to work with to meet the criteria is to put in a smaller program, and then we will only meet criteria over this smaller range of coverage. 2.3 Higher load shedding levels should be encouraged if it makes sense While we do not believe that any party (utility, group, region, etc) should be forced to shed more than the minimum called for in the Standard, we believe we should let them shed more load when there is an advantage to doing this. This will be the exception, but some areas, such as parts of Canada, are obviously prone to islanding and these areas often have high load shedding needs. Some areas shed 60% of system load, or perhaps more. Historically, UFLS standards have been minimum standards which tell utilities they must shed at least a certain amount of load. Regional programs allowed or even encouraged utilities to shed more load when it made sense. It seems obvious that this intent is still there, but the problem is that the "measures" chosen for this standard actually discourage this. 2.4 Frequency is subjective, and should not be a "compliance measure" PRC-006 uses frequency and voltage as "measures" to ensure UFLS programs satisfy reliability objectives. I believe these are both inappropriate "measures". Both voltage and frequency are highly subjective and are not really a good way to indicate if a load shedding program is going to get the job done. Let's review the basics: 1) frequency drops following loss of generation or import with an initial rate of change of frequency defined by the size of the overload and the system inertia, 2) since turbine power can generally be assumed to be constant, this frequency drop increases generator torque as torque=power/speed, 3) load torque drops according to the load damping characteristic, and 4) we eventually reach equilibrium at a new lower frequency where once again Generation = Load at the new synchronous frequency. (A footnote: turbine power is not always constant during a frequency decline, combustion turbines have thermal limits requiring the power output to be lowered as frequency drops, causing a further drop in system frequency. Governor response on these units will only be momentary before thermal controls take over.) Now let's consider how these variables affect our performance "measures". For a given overload, final frequency is a direct function of the load dynamic characteristics which are not precisely known. We know the damping constant used in models is in the range of 1 to 2, and anything in that range is "typical". Low damping will give the lowest frequency and highest frequency deviations. The equivalent system based inertia H = sum of MW-sec of online units/total Pgen, is a function of different unit dispatch scenarios. For a given overload, high inertia gives slower rates of frequency change, better relay coordination, a higher minimum frequency, and slower frequency recovery. Small inertia gives high rates of frequency change, lower minimum frequencies, relay coordination problems and possible overshedding. With the wide range of "valid assumptions" to choose from, folks can essentially pick the off-nominal frequency results they want to show for compliance purposes, and if results of a large program don't look good enough, they can switch to a smaller program so that it satisfies the "measure". Choosing modeling assumptions is not "gaming", it is standard engineering practice, but a single set of assumptions does not tell the full story. I would rather have measures which encourage folks to look for potential problems instead of measures which punish them for finding such problems. I would also like to see the measures encourage larger UFLS programs when that meets some identified need. To further complicate matters; let's compare a large UFLS program (sheds 45% to 60% or so) with a small program (sheds 25% of load). Let's assume they both have 5 stages of load shedding. Over the range covered by the small program, it will work in a more refined manner than the larger program as it uses smaller load blocks. For overloads between the sizes of the two programs, only the larger program will work. So how should performance be judged? There is a reason I chose the same number of load shedding blocks in this example, and it is worth digressing for a moment to explain. As a practical matter, UFLS programs can only make use of 5 or 6 high speed load shedding blocks while still achieving good relay coordination and while also keeping the minimum frequency from dropping too low. This is not a hard and fast rule, but it is what I have seen in my study work. This is an effect related to inherent time delays introduced by relaying detection times and breaker operating times, and the frequency spacing needed between relays to achieve relay coordination. Of course if we are willing to toss out relay coordination we can improve the underfrequency response at the expense of creating overfrequency problems which then have to be hammered back by automatic load restoration or the equivalent (for instance, Manitoba Hydro can drop power coming in on DC lines to balance load with generation but that is a very unique situation). 2.5 Voltage is subjective, and should not be a "compliance measure" Overall, I am more concerned with the magnitude of the voltage out at the load rather than volts/Hz issues at the generator. The volts/Hz issues are already well covered by IEEE/ANSI standards, and this is difficult to model since exciter/voltage regulator models typically do not include a volts/Hz function, so the automatic reduction of the generator terminal voltage which occurs in real life does not show up in simulations. During load shedding the generators will be pulling the voltage down anyway. My understanding is that volts/Hz issues are less restrictive than other underfrequency concerns/factors. This would be something we need to look at if we allow frequencies to drop to 57 Hz or less. (Unit terminal voltage is controlled by the voltage regulator and outside of the transient time frame, we can assume the steady state voltage will be limited to 1.05 pu to .95 pu, so 1.10 v/Hz gives problems in the range of 60*1.05/1.1=57.27 Hz to 60*.95/1.1=51.8 Hz.) In addition, units are only at risk if this voltage regulator function fails, or if units are in manual voltage control. In that case the backup volts/Hz relaying will trip a unit. I am not too worried about voltage regulators failing and do not consider volts/Hz as a major risk factor. Usually volts/Hz is not given too much attention when designing UFLS programs. I am not aware of any of the existing UFLS standards having any volts/Hz criteria, but perhaps I am mistaken. I suggest the volts/Hz requirement be removed from PRC-006 because it really does not add anything which is not already covered elsewhere. 2.6 Overvoltage as a source of additional uncertainty As load is shed we can get overvoltages out at the load which effectively increases system load. To some extent this voltage related load increase offsets the benefit of load shedding. Voltage control issues during load shedding/system break up are extremely difficult to assess. Voltage changes are a function of changes to VAR supply/consumption, as well as inversely proportional to system strength (i.e. fault MVA magnitude). System breakups and associated loss of generation can weaken the system and make voltage control much more difficult to manage. There is a general recognition that some capacitors need to be shed with load, but such details have to be worked out and refined at the local utility level as part of the load shedding implementation phase. I do not have a good idea of what is "the best that we can do". I imagine it will vary with disturbance. I am not sure how this should be handled in the standards drafting process. I want to create an awareness of the problem so that folks give this some attention, and apply good common sense, but I do not want to turn this into any kind of "measure". This is more of a bottom up type of analysis where very specific local detail has to be considered, where the rest of the UFLS conceptual work is the top down, big picture stuff where we do not need to address such specific local details. I am confident that utilities will do the right thing once set on the right course, and these types of details can be reviewed in the subsequent periodic UFLS assessments and things tweaked

if needed. I just don't know how to make this process any better than this. We have to be careful that we do not try to micromanage this difficult task. The MRO UFLS effort tried to anticipate as much complication as possible, but we could not cover all of the inherent uncertainty involved. No one could. The main source of uncertainty we could not deal with is how potential overvoltage's may increase load and decrease the effectiveness of the load shedding program. This gave us additional justification for using a "no net governor response" scenario for evaluating coordination between load shedding and generator protection (this voltage uncertainty is not the only reason for using a no governor assumption: basically units that are base loaded cannot respond to underfrequency, power/load controllers may override governor action after a short time delay, combustion turbine thermal limits will quickly override their governor action with power dropping off faster than the frequency decline, wind generation may drop off and would not have a governor anyway, and so forth; the bottom line is that we do not know what level of net governor type of action we can count on, and what little we get may be offset by increases in voltage). 2.7 PRC-006 and PRC-024 are forcing UFLS programs to the least common denominator PRC-024 and PRC-006 both fail to satisfy a comment made in the NERC UFLS unofficial comment form which indicates the UFLS standard is supposed to provide an appropriate level of reliability, not the least common denominator. Somewhere the NERC UFLS standards drafting team also concluded that "UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics". Programs which shed different amounts of load will inherently have different performance characteristics, and work over a different range of overloads. By setting frequency based performance criteria these two standards are definitely forcing things towards the lowest common denominator as the proposed "measures" can only be met by a smaller load shedding program. The PRC-006 UFLS standard and companion PRC-024 establish tightly defined performance characteristics which at best will just barely work for a 30% load shedding level. Perhaps I should be more careful and say it works for a 30% load shedding level for a range of assumptions, but not for all of the conditions/modeling assumptions that we looked at in the MRO study. Those settings certainly do not encourage a robust UFLS program. This "one size fits all performance envelope" approach only works if we use the worst case (largest UFLS program) as a basis for the performance envelope. We can characterize these larger load shedding programs as having to accept more tradeoffs. The minimum frequency will be lower, the maximum frequency will be higher, larger load blocks will have to be shed making things more drastic, and the programs are likely to be more susceptible to relay coordination problems (due to the high rates of frequency decline associated with the large imbalances). What you get for these tradeoffs is a bigger safety net. The generation coordination part of UFLS analysis should be addressed directly in PRC-006 as something that needs attention, but the specific details such as those presented in PRC-024 need to be worked out at the UFLS working group level in coordination with the study process that designs the load shedding program. This type of information is not appropriate for NERC standards. The off-nominal frequency limits in PRC-024 should never have been created and should be eliminated. PRC-024 is poorly thought out and is going to do much more harm than good. Setting generation protection up front before casework is run is putting the cart before the horse. This is an attempt to micromanage the UFLS analytical process without having a full view of the big picture. It just represents someone's judgment call concerning what is appropriate. It does not accurately reflect generation capabilities and no technical basis was provided to justify the "measures" in the standard. In my opinion PRC-024 is seriously flawed and actually is a serious threat to reliability. It also conflicts with the new MRO UFLS program we developed, and if other regions did the type of analysis that we did, they would probably find this causes problems for them as well. (Most UFLS programs do not go to as great of lengths as we did to look for potential problems over the full range of overloads covered by the program.) I am well aware of generation off-nominal frequency issues and concerns, I have had my eye on this for 20 years. In the MRO UFLS study we did all that we could to minimize the off-nominal frequency exposure to generation, even going to the point of designing the load shedding program as the first line of defense for generation. This is achieved by designing the UFLS program to force quick frequency recovery even if we get no net governor action. This is achieved by having small blocks of load shed on delay that only trip if frequency recovery is sluggish. The point to make here is that the PRC-024 standards drafting group is not the appropriate group to be deciding on what tradeoffs are appropriate for coordinating load shedding with generation protection requirements, and they are ignoring some important "real world" consequences. Some of what is in PRC-024, if implemented, would be catastrophic for the grid. 2.8 Overfrequency issues The diagram from PRC-024-1 suggests that overfrequency tripping of generation is going to be allowed in similar fashion to how underfrequency tripping of generation is applied. Extreme caution is needed. If we add relays to instantly trip generation according to the overfrequency part of PRC-024, we will have multiple units tripping at the same time and we will cause a blackout. I would call this a really big fatal flaw. Units self protect on overspeed and we do not have to add additional overfrequency tripping relays unless this is a planned activity used to balance load and generation. It is important to have some understanding of overspeed issues and related controls, so I need to take a moment to cover this subject. In addition to the normal speed regulating governor, all power plants already have internal emergency overspeed controls to deal with full load rejection (loss of all lines out of the plant with turbine running flat out). These controls also activate on partial load rejections (overfrequency during islanding). These controls can have many names: emergency or preemergency governor, overspeed controls, load rejection controls, trip anticipators, or something similar. We do not want to be modifying these controls and their settings, but we need to understand how they operate. These controls vary at each plant so the following discussion has to use generalities to make my point. I am most familiar with controls on steam plants so this discussion applies to that type of generation. Generally these emergency overspeed controls try to limit peak speed to something below 110% by closing all turbine valves, and if this fails, the unit is tripped to prevent mechanical damage. To limit peak speed, these controls have to start closing valves as units start to accelerate. These controls are applied a little differently at every plant, but have to act before things get out of control, so they generally activate between 61.2 Hz to 61.4 Hz on low inertia units (in this instance I am talking of the inertia constant in dynamics, H=MW-sec/Mbase of machine), and sometimes not until 62 Hz if unit inertia is high. These emergency overspeed controls are in addition to the normal governor, and are much more drastic and just slam all steam valves shut. These emergency overspeed controls are not modeled in stability cases and I bet that most planning engineers have never given them much thought. It seems we never see frequencies any higher than about 61.4 Hz following a breakup, while stability cases might indicate frequency should have gone much higher. These would be the controls responsible for that disconnect between the real world and the simulation world. Outside of the inherent factory installed overspeed controls, we have to exercise great care and caution when applying additional relays to trip generation on overspeed. The purpose of such tripping would be to

restore the balance between load and generation within an island. If this is done, we need to be aware of the risk involved. Because these load rejection controls slam valves shut, the system frequency is unlikely to get much higher than 61.4 Hz (for a system which is primarily coal fired) no matter how large the initial imbalance. (Most steam units that I have looked at activate around 61.2 Hz to 61.4 Hz, and at one time I looked at every unit in Colorado and Wyoming to get a feel for what is typical.) Once these controls activate, frequency is no longer a measure of the imbalance between load and generation. We cannot keep steam valves closed for too long, constraining all the steam with the boiler going full tilt, or else random unit trips will start to occur due to any number of internal plant problems. We do not know how much time we have to get valves back open before we are at risk of losing a unit. Someone estimated 15 seconds (I can't say if this is right or wrong, but it sounds about right to me), and then internal plant problems will start to occur. Often we see that one plant trips first and this helps. That reduction in generation rebalances things for other units allowing steam valves to reopen. The random nature of what happens in response to overfrequency complicates any planned unit tripping actions to correct the imbalance. If the sum of planned and unplanned tripping is too much, we cycle into another underfrequency event. This illustrates why dedicated unit tripping on overspeed has to be considered carefully, and should only be applied as a method to rebalance load and generation, and not as overfrequency protection of the type we apply for underfrequency. If generation is tripped to correct overspeed in an island, it has to be done in small increments (equivalent to about 1 to 1.5 % of remaining load) and trip times have to be staggered. For the purpose of balancing generation with load, unit tripping should only be implemented on a few selected small units. The trip setting would have to set at frequencies no higher than something like 61Hz to 61.4 Hz, or else these relays may never pick up. Picking the right delay times is tricky and would have to be based on simulation results. In practice, it may make more sense to do automatic load restoration to rebalance. This is something that has to be studied on a case-by-case basis. As a side note: in the MRO UFLS effort completed in 2007, we were very concerned about overfrequency. This led to changes from the MAPP program of shedding 3 blocks of 10% to a program shedding 5 blocks of 6% . We then focused on adding adequate spacing between relay settings to reduce the risk of overshedding under our worst case assumptions of large overload, low inertia, and low load damping. The compromise was we had to accept lower minimum frequencies. 2.9 We need realistic minimum frequency limits on generation that meet load shedding needs I also have concerns with the chosen minimum frequency in PRC-024, and the time delays proposed at different frequencies. Although the MRO UFLS Taskforce expects that under "typical conditions" that minimum frequency will be above 58 Hz, (for loss of generation/import of up to 30% of system load in the island), our worst case simulations indicate we could briefly dip below that, and we used our worst case results to set generation protection frequency settings and delays. In addition, our "equivalent inertia" modeling approach ignores machine to machine oscillations which might cause frequency at different locations to differ by .2 Hz or so as the system frequency rings down. For this reason, we chose 57.6 Hz as the point where instant tripping of generation is allowed. This is below our worst-case minimum frequency of 57.77 Hz (for a very low inertia, low damping, no governor scenario that is perhaps overly pessimistic). This instant trip setting for generation can also be justified in another way. Our design criteria set a target where we wanted the minimum average system frequency >= 58 Hz, and we seem to meet this for most conditions. This 58 Hz minimum frequency seen in our models then has to be adjusted by about - .2 Hz to account for machine to machine oscillations seen in the real system and not in our model, plus about .2 Hz margin to ensure good relay coordination. This takes us back to 57.6 Hz as the appropriate frequency for the instant trip setting on generator off-nominal frequency protection. Programs which shed more than 30% of load will need to relax generation protection and accept lower frequencies and longer time delays. 2.10 An example of coordination between load shedding and generation protection as performed in MRO UFLS study In order to come up with the MRO generation protection settings we monitored time spent in frequency bands spaced .1 Hz apart and we consider the performance over the full range of coverage (0 to 30 % loss of generation) and considered a wide range of assumptions concerning system based inertia (H system base = total MW-sec stored in rotating mass divided by P gen) and a range of damping, in addition to a possible range of governor actions. We optimized the program to minimize time spent below 60 Hz while addressing all the other constraints we had to deal with. Once we knew the expected worst case times in each .1 Hz band below 60 Hz for the optimized program, we came up with the stair step type of generation frequency versus time delay settings that gave a reasonable fit to the expected worst-case time versus frequency information (plus some margin) with the fewest frequency bands. To fully understand what we did you will have to refer to the MRO UFLS report on the MRO website. The short version is that we ran 1000's of cases to arrive at our conclusions. What we came up with for generator underfrequency protection minimum time delays is what we need to ensure the load shedding has time to play out to restore frequency and to give some margin to ensure relay coordination. If we shorten the generation protection time delays and raise the frequency setting for the instant trip point, then there is a narrower range of conditions for which the UFLS program would be expected to work as intended. Our safety net becomes less robust, we make things less secure. 2.11 Load shedding can be used as the first line of defense when it comes to generation underfrequency protection The MRO load shedding program is designed to be the first line of protection for the generators because it is designed to force frequency recovery even in the absence of governor action by having small blocks of load shed on delay to quickly bring us back towards 60 Hz when recovery is too slow. 2.12 Generation off-nominal frequency protection settings imply more risk than units may experience Although there is a chance that frequency may be slow to recover as a worst case, most of the time it will recover much faster than the times we used for generation tripping coordination. The expected time spent below 60 Hz sort of takes on the form of a probability density function. This type of information gives a better idea of what units may be exposed to, and the real risk is less than what the generation protection settings may imply. Therefore, our approach was to coordinate generation off-nominal frequency protection to match the worst case frequency recovery times seen in our simulations after first doing everything possible to minimize underfrequency exposure to generators when designing the load shedding program. For the MRO region, the recommendations of the MRO UFLS report should take precedence over what is being proposed in PRC-024 and PRC-006. 2.13 UFLS programs which shed higher levels of load need less restrictive generation off-nominal frequency protection In MRO, we recognize that the Canadian portion of MRO needs to shed more than 30% of connected load. The MRO UFLS report indicates that any program that needs to shed more than 30% of load will need to relax the MRO generator off nominal frequency time delay settings for generation and accept longer delays and lower minimum frequencies. This is an engineering reality. The Off-Nominal Frequency Capability Curve from PRC-024 does not give this kind of flexibility. Alternately, some improvement on minimum frequency can be realized

by designing a program that oversheds but then the program will be prone to overspeed problems. This approach can get scary. Some improvement in coordinating with generation needs can be achieved by designing the UFLS program to start shedding at higher frequencies. This gives a corresponding improvement to the minimum frequency but this action often creates coordination problems with neighboring programs. On the other hand, sometimes you want one area to start shedding first to meet some specific objective. This is just another example of how every single facet of UFLS program design has to be carefully considered. In many ways, this is no different from any other type of planning or operating study work. The bottom line is that this reliability standard writing process should not replace engineering judgment. Utilities need flexibility so they can make the necessary compromises after all things are considered. Making adjustments to generation protection frequency settings and associated time delays is most likely the best approach to ensure coordination with larger load shedding programs. We must give sufficient time for load shedding to act even if it means we need to accept some additional potential loss of life to generation for some hypothetical underfrequency event. I believe this is prudent and will not place undue burden on generation. 2.14 The starting frequency of load shedding programs In MRO we would have considered an UFLS program which starts to shed load at frequencies above 59.3 Hz (probably 59.5 Hz) if neighboring regions would have shown interest in doing the same. However that was not the case. All the programs in the region started at 59.3 Hz so we stuck with that. If we had increased the starting point to 59.5 Hz, we might have increased the risk of dropping load on power system swings where no load dropping is needed (if so, this would probably be isolated to a few buses), but we would have improve the minimum frequency and this helps larger load shedding programs meet coordination needs. 2.15 Turbine/Generator underfrequency capabilities To talk about off-nominal frequency capabilities of turbine/ generators, I will once again have to generalize a bit. The continuous operating range for no accelerated loss of life is typically 60.5 Hz to 59.5 Hz. The frequency which requires an instant trip, for most generation (I will ignore combustion turbines for now), is below 57 Hz for steam, and as low as 56 Hz or lower for hydro. Steam turbines are more restrictive than hydro because of blade resonance issues and the result is that the time versus frequency limits are logarithmic with considerable operating time allowed just below 59.5 Hz and very little operating time is allowed at the lower frequencies. Limits are generally based on a theoretical “probable loss of life” after being subjected to some total time spent below 60 Hz over the life of the plant. This also fails to take into consideration that units get maintained and some issues are corrected before becoming problems. So we have to evaluate what fraction of this theoretical off-nominal frequency based accelerated loss of life needs to be used to respond to a rare and infrequent islanding event, but in the end this is a judgment call and is driven by what we have to accept to get the job done. Limits for combustion turbines seem to vary, with instant tripping suggested anywhere from about 57 Hz to 58.2 Hz. I know less about these than I do about other types of generation, but we learned what we could about these during the MRO UFLS study process. The group that did the last WECC UFLS review got quite involved in this area of investigation, and the MRO group benefited by consulting with the former chairman of that group. 20 years ago the combustion turbines were not showing up as a limiting factor, or we failed to notice the issues. I personally question the basis for the 58.2 Hz instant tripping point that is recommended for one make and model. It is hard for me to imagine that a very brief dip below 58.2 Hz is going to be a problem when considerable operating time above 58.2 Hz is allowed. This low “instant trip” frequency setting is out of line with historical industry practices and our industry has to encourage manufacturers to build equipment with better off-nominal frequency capability than this. 2.16 Don’t get too conservative with Generation off-nominal frequency protection settings I feel that many times utilities try to get too conservative in how they want to set generation-off nominal frequency protection to the point where this may affect UFLS. If we set this too tight we might end up with a blackout. Black start plans are where the real off-nominal frequency loss of life can be chewed up. Generally such plans call for this protection to be disabled so that it does not interfere with restoring the system. Another issue that I have heard several times as justification for using very conservative generator off-nominal frequency limits is that some folks are claiming their insurance sets underfrequency limits for their generation. Who is to say if the terms of the insurance coverage even makes any technical sense? This hardly sounds like a legitimate reliability issue. From my perspective, this seems at odds with system reliability. I also expect that independent power producers will not be as interested as a traditional vertically integrated utility would be in trying to prevent the grid from collapsing. I expect that at least some of them would just as soon shut down as quickly as possible instead of riding the disturbance out. We have to ensure they do not do this or it may have catastrophic consequences. 2.17 Short time delays being proposed for generation protection at frequencies close to 60 Hz is a huge risk to the grid, (i.e. at 59.3 Hz, 60.7 Hz) We need to allow much more operating time at the frequencies closer to 60 Hz than what the NERC standards drafting teams are proposing in PRC-006 and PRC-024. The proposed time delay limit says we can only operate at or below 59.3 Hz or at or above 60.7 Hz for 30 seconds. This is completely unrealistic and a huge threat to system reliability because these standards are essentially giving generation permission to set protection relays accordingly. Remember that once generation starts to trip on underfrequency it can quickly cascade into a blackout. This entire subject of what is appropriate for generation off-nominal frequency protection is something for the experts in study groups to work out, and should not be addressed in either of these standards. At frequencies close to 60 Hz the appropriate generation protection time delays need to be on the order of 30 minutes or longer instead of 30 seconds as proposed by PRC-006 and PRC-024. The analysis we did in MRO indicates there is a chance that we will take longer than 30 seconds to get above 59.3 Hz even if our UFLS program works as planned. Remember we did this “bandwidth” type of analysis so we looked at more conditions than most have. We looked for those narrow windows of vulnerability where things “stick” or respond in a sluggish fashion. We can show that any UFLS program will have some combinations of overload and modeling assumptions where frequency recovery is slow and sluggish. If you don’t look for this problem, you are not going to find it, so we conclude the other regions would have as much trouble meeting this as the new MRO UFLS program. Perhaps an intuitive example will help. Basically over the range of coverage provided by load shedding, there will be certain combinations of factors which lead to frequency settling out just above where the next block picks up, and then we have to rely of governor action (or additional small blocks of load shed on delay) to pull the frequency back up. The rate of frequency recovery is also going to be a function of inertia, and if we have lots of units on which are partly loaded, the effective “system based” inertia will be high and rates of change of frequency will be lower. In comparison, if frequency would have dropped a little lower we would have quickly shed load and driven frequency up above 60 Hz, potentially reaching our maximum frequency. Another example to consider is what happens if the system overload is just a little larger than the size of the UFLS program? All load is shed and we are still below 60 Hz, but frequency might be close enough to 60 Hz for operators to respond

if they are given sufficient time to respond. 2.18 Generation protection settings also have to anticipate what happens if UFLS fails My biggest concern with use of short time delays at frequencies above 59 Hz is based on a completely different issue. Murphy's Law is alive and well when it comes to power systems. All of us have to consider what might go wrong during a system breakup. Breakups can be chaotic and different each time they happen, and consequently load shedding performance can vary. There is a chance the "perfect plan on paper" may fail to work as desired in the face of some unanticipated event. At some point operators may have to intervene, and they need assurance that generation will not be tripping as they manually try and drop load. The fact that frequency can stall us out below 59.5 Hz is reason enough to insist that we use generation protection time delays according to actual equipment capabilities. In general, generation off-nominal frequency protection time delays need to be longer than the expected frequency recovery times shown in simulations to give us some margin, and as we get closer to 60 Hz, we want to take advantage of the long delay times allowed by actual equipment capabilities. This is needed as part of the "hedging our bets" process. This helps compensate for the uncertainty we cannot factor into the program design like relay failure, operator error, random events, loads changing in real time (affecting block size as % of system load), effects of voltage transients that effectively increase load, and so forth. A real life scenario many of us have seen before is where UFLS programs cycle between underfrequency to overfrequency and back into underfrequency. On the second drop into underfrequency, we no longer have all or any of our automatic load shedding left. With luck, the frequency will stall out close enough to 60 Hz to allow manual operator initiated actions. Planners try to prevent this in the design, but in real life this cannot always be prevented. For instance, load shedding itself can overstress lines and cause further breakup of an island into smaller islands, one with a surplus of generation and one with too much load. The island with too much generation is going to suddenly have severe overfrequency problems. Emergency overspeed controls which are in place to deal with full load rejection will kick in somewhere above 61.2 Hz (as previously described). At steam plants these load rejection controls will slam all valves shut. Power plants can't stay in this condition for very long before something gives. Let's say this leads to unpredictable random tripping of thermal generation, and frequency drops back below 60 Hz. As frequency drops the remaining steam turbine valves open back up, so the initial loss of generation my save the rest of the generation and frequency may actually settle out below 60 Hz, but with frequency still high enough that actual equipment capabilities would allow operators plenty of time to respond. We need to take advantage of this capability, and set generation tripping times accordingly. Another example would be having an overload which is slightly higher than the size of the load shedding program. All load is shed, but frequency remains below 59.5 Hz. We then rely on manual operator actions to pull us back the rest of the way. 2.19 A very troubling trend One of the most troubling things we uncovered in the MRO UFLS effort is that some manufacturers are now designing equipment which does not have the off-nominal frequency capability it once had. It seems this has occurred with CT's and is probably also happening with wind generation. I mention this trend as it is important that we don't build in weak links like this as the system expands or else we are going to seriously affect reliability. We need units which can briefly operate down to at least 57 Hz to improve chances of surviving islanding events. Future trends in general are all at odds with being able to create a good underfrequency safety net. If NERC prescribes limits which never allow us to operate below 58 Hz, or to limit operation at 59.3 Hz to only 30 seconds, equipment will start being built accordingly. Combustion turbines cannot hold constant power as frequency drops unless they were only partly loaded to begin with. There are thermal issues involved, which is why fully loaded units only have a momentary governor response to underfrequency. The governor is quickly overridden by the thermal controls. The percentage of power which drops off due to a frequency decline is going to be about the same percentage as the percent change in frequency, or higher. A lot of new CT's have been added over the last 10 years or so, and we are likely to see more of these in the future. High concentrations of wind generation are really going to cause problems unless more sophisticated designs are used. The problem is that older units are inherently unstable and will just trip off right away. Newer units can probably operate down to 57 Hz, but all inertial effects are masked from the system, so system inertia is going to drop and UFLS relay coordination is going to become very difficult because that low inertia means high rates of change of frequency and this can affect load shedding programs in several ways. In the MRO UFLS program, we anticipated this problem and examined lower "system based" inertia than what we have today. We saw coordination problems, but this information was still used to help us define a robust UFLS program. It was obvious that coordination would be next to impossible if inertia got lower than what we looked at. Lower system based inertia means lower minimum frequencies and higher frequency overshoot. (This is a consequence of relay detection times and breaker operating times being too slow to stay on top of the fast drop in frequency, so we end up with relay coordination problems and shed too much, too late.) I am not aware of wind units having any type of governor although I was told by an individual in GE's Power Systems group that designs will be changing over the next 10 years. For instance, GE is adding a governor to their wind generation. I am not sure how that works. Most likely it would work well on overfrequency, but I am not so sure about underfrequency. Likewise they might be able to use software that controls the power electronics associated with variable slip induction generator to unmask the inertial effects (or mimic such effects) to help the grid a bit. However, actual inertia of wind generation is still going to be low. I also heard that a new trend is going to be use of permanent magnet synchronous generators for wind generation. Synchronous generation is probably going to be an improvement over induction generation, but I have no idea if this will actually be a benefit to the system or not. Whatever the wind industry comes up with, it is unlikely to be as robust and useful as traditional steam and hydro generation, and it will just make the task of providing a safety net all the more complex, or perhaps nearly impossible, once huge amounts of wind generation are added to the grid. 3.0 Observations concerning historical reliability criteria, and a proposal to adopt a different type of "measure" to assess UFLS reliability 3.1 Reasonable Expectations It appears that engineers recognize that we cannot apply performance measures to real life load shedding events since it would be an inconsistent application of how we apply operating type criteria in general to such low probability multiple contingencies. In addition, the parties who are trying to fix the problem do not need to be blamed for the problem itself should they be unable to "fix it". That is sort of pointless. I believe that engineers also seem to recognize the only perfect program that exists is the one on paper. In real life it has to deal with things we probably have never anticipated and if disturbances are too severe, load shedding may not prevent collapse. Load shedding is just a tool and it has limits. That is just an engineering reality. It should also be obvious that a lot of coordination is involved. 3.2 Coordination is the key to ensuring reliability objectives are met Good coordination is going to be what ensures reliability. However we sure seem to be doing things which discourages coordination at large. This new deregulated world has defined transmission as separate

from generation when in reality all these parts together form a giant complex machine called the “system”. For compliance, we created the concept of “Legal Entities” who can be sanctioned, and entities such as NERC regionals that are apparently something else. We invented terms such as planning coordinator. This all gets confusing, especially to me, as I have had little experience with structural changes going on. What I see is that much of the carefully built up infrastructure that we had to promote reliability is being altered to the extent it is hard to recognize just where we are at today. As we keep creating distinctions which do not follow engineering realities, it will just make all of our coordination tasks much harder to achieve. It is hard to see how this helps reliability. For instance, I was told the NERC regions cannot be in charge of design and analysis of UFLS programs (in conjunction with members of course) because they are not a “Legal Entity”. However this is how reliability matters were always coordinated and this is still the logical way to achieve coordination between all of the parties who need to get involved. All of us in the industry have to work together and pull in the same direction to develop an appropriate safety net. The NERC regions have the organizational structure to pull everyone together to do this type of coordination through taskforces that represent the industry at large. It is necessary to get a broad base of different people involved in the UFLS study process. It ensures you have lots of eyes on the product, lots of different viewpoints to consider, and it also helps in selling and explaining the final program to everyone in the end. 3.3 We have to consider the system in total When it comes to analysis, the power grid is all one giant complex machine all the way down to the customer load. You have to consider all the parts to figure out the dynamic response of the whole. We have to consider everything which affects the frequency decay dynamics. There is no distinction that can be made on the basis of voltage class of the components of the system. This is why I am a little uncomfortable with excluding some generation from having to coordinate with load shedding programs as done in PRC-024 and PRC-006 just because such generation is connected to a lower voltage. If such generation, in total, is significant to the study work and final UFLS program, then it needs to be included. Let the study group decide what is significant or insignificant. 3.4 The evolution of PRC-006 I understand that PRC-006 has now evolved into something closer to a “continent wide” planning type of standard to guide us in designing UFLS programs. I have tried to explain why the tradeoffs associated with load shedding programs are best evaluated by groups of technical experts which are closest to the problem and why this standards process should not be micromanaging the analytical process or be setting design type of performance criteria. Likewise, it is a poor idea to have a standard such as the proposed PRC-024 that tries to establish generator protection settings up front. I see these approaches as actually being a threat to reliability by providing the wrong incentives (I also have technical reasons why I do not agree what is being proposed). NERC should allow the technical groups to work out these types of details. Such groups can give this subject the thought and focus that it deserves, and this careful deliberate thought process is what will ultimately ensure we are meeting reliability objectives. 3.5 A recap of my concerns I believe that I have explained why I am uncomfortable with the idea of using specific frequency and voltage characteristics as a design “measure” in the UFLS standard. I will recap the issues. The various performance objectives of limiting underfrequency, limiting overfrequency, and of providing the largest safety net possible are mutually exclusive. The easiest way to satisfy all three (perhaps the only way) is to put in a smaller program and then the program will work well over this smaller range of overloads but will be inadequate if larger overloads occur. I believe we need to allow programs which are larger than the minimum, when appropriate, and those programs will have poorer performance according to these “measures” but I will argue that only the program which is “large enough to get the job done” will give us the reliability we are looking for. I also recognize there are limits to what UFLS can accomplish, which is why I do not want to mandate that UFLS programs have to shed more than the stated minimum, but I want to encourage folks to do this if it makes sense. Neither the frequency nor the voltage “measures” really tell us if we have the right safety net in place and both measures are subjective (i.e. what performance for what set of assumptions). Concerning voltage, I recognize that volt/Hz issues exist, but I do not feel this needs to be addressed in the standard. The real issue is how to minimize overvoltage problems as we shed load. To some extent I believe this discussion also helps explain why it can make sense to have different UFLS programs for different portions of the system. That is because different areas have different needs, and possibly unique regional aspects to consider. The final UFLS program definition is just an outcome of working though the problem and iterating towards a best compromise for UFLS program design. There is no one single “best” program. We have lots of options and each represents different tradeoffs. In reviewing technical literature, we find there are also lots of different opinions expressed by different authors, and I imagine this influenced how programs were created in the first place. I believe the existing load shedding programs in North America are probably getting the job done as long as coordination with generation protection has been achieved. Some programs may be a little more refined than others, but load shedding is inherently a crude and drastic action. A periodic review process will go a long way to ensuring we keep programs up to date. We do not want this review process to be too much of a burden, but we want some process in place so that we can do detailed analysis if needed. My experience has been that a full blown UFLS study process will take 2 to 3 years to complete, perhaps 1 to 1.5 years if folks are fully trained, spend all their time on this one subject, have the study scope worked out ahead of time, and have all the tools developed that are needed. That is what it took groups I have been involved with to collect the information, to build the models, to run meetings, to do the analytical work, and so forth. I would not want to have to do that over and over again on a 5 year schedule. A much more simplified review would be appropriate for the 5 year review. A full study mode type of ground up review is only needed once in a long while or in response to some major break up or in response to drastic changes to the topography of the grid. I feel that UFLS “measures” used for compliance purposes should stay away from frequency and voltage. We need a different type of measure. UFLS is really sort of something different and unique, and I think that justifies treating it differently than other Standards to the extent that it makes sense to do so. All the other criteria try to keep us from ever getting to this point. UFLS is what we do when we are past the point where most criteria apply. It is a drastic, one shot, last ditch effort and we can’t make it into something other than what it is. Some accelerated loss of life to equipment will be involved. Loss of equipment life and financial costs are also associated with a system that goes black. We need to consider all of these tradeoffs, especially when people get too conservative on generation protection to the point where if affects UFLS performance objectives. We need flexibility to accept the right tradeoffs. The UFLS standard can avoid the subject of voltage and frequency performance altogether since we know this will be addressed in the study process in an appropriate level of detail. 3.6 A suggestion to adopt a completely different type of “measure” I have consistently stressed how UFLS analysis is an iterative process. I hope everyone can understand why I feel this standards drafting process also has to be iterative, and why we may need

to change course as we move along the learning curve. I believe the standards drafting teams need to back up and try a different approach which emphasizes “measures” which consider a completely different aspect of UFLS related effects on reliability. The question is, what are the right measures? The first thought that comes to mind is that load shedding enhances reliability by creating a safety net. Perhaps we should be only be checking to see if the safety net exists, to see if studies say the safety net is an appropriate safety net, and so forth. Would it be possible to use these aspects of the issue as our “measures”? I think it makes perfect sense to “measure” if we are fulfilling the basic aspects of load shedding obligations. The “measure” would be “have you done activities x, y, z?”. We would then skip this entire discussion of what type of performance, on paper, is appropriate. Instead we would focus on the big picture, which is to make sure we have a reasonably effective safety net in place. The “measures” could become simple pass/fail checks to see if we have covered the basics of implementing an appropriate UFLS program. I suggest that we keep it really simple. It will be easy to check on things like: 1) has an appropriate program been designed which satisfies a checklist of items that have to be considered such as coordination with generation protection, 2) has the program been implemented, 3) has the program been periodically reviewed, 4) have any changes that came about from the review processes been implemented in a timely fashion, and so forth. I know I am in the position of having to sell this approach, as this is not what FERC and NERC set out to do. However, when you look at all the complexity involved, and what the bottom line is, this approach makes sense. I am sure it would be acceptable to the industry and that it would satisfy reliability objectives so long as we get the appropriate study groups in place. That really means getting the right people involved, who have the needed skills to work through things. I think a NERC region has the organizational structure to pull this type of coordination off. We are all familiar with that structure. Inventing some new type of group structure just adds another layer of confusion to deal with. The standards should stick to the broad-brush type of stuff. More to the point, this standard should be written to ensure the following: * That Automatic Underfrequency Load Shedding (UFLS) programs are properly developed, documented, and coordinated. This includes coordinating generation off-nominal frequency protection settings with the expected frequency recovery characteristic of the load shedding program. * That groups/regions have studied UFLS and have designed an UFLS program that fits the unique characteristics of the region (including any subregions) and that UFLS programs address any specific issues that are relevant to UFLS. * That groups/regions have documentation that specifies the details of the desired UFLS program so it can be implemented. * That groups/regions do periodic reviews including reports on actual UFLS performance following major disturbances. * That individual utilities have implemented load shedding in a fashion which is a reasonable fit to the stated regional load shedding program and that documentation is available (the term “reasonable fit” is used in consideration that no single utility can ever get a perfect match to a something like 5 blocks of 6%). * That each group/region sheds at least a minimum amount of load. That some form of coordination or dialog exists between groups/regions which study load shedding in adjacent areas. * To ensure that modeling data is collected and compiled for stability cases We recognize that PRC-006 addresses some of these points adequately, but as previously discussed, we have serious concerns with how some of this is being handled. Let the groups/regions define: * how much load to shed in total (it is OK to set a minimum level in the NERC standard, so long as we are clear that this implies a higher level might be more appropriate) * size of load shedding blocks * frequency setpoints * targets for min/max frequency deviations and allowable times above and below 60 hz (these are design targets only, and may have to be reconsidered and revised after looking at study results…this is an iterative process that has to be carefully thought out as study work proceeds) * generation off-nominal frequency tripping minimum time versus frequency protection settings to ensure coordination with load shedding * analytical methods * any other unique requirements or aspects of regional programs 3.7 The existing NERC UFLS related guidelines and criteria are excellent As far as UFLS design goes, the broad guidelines in the existing NERC UFLS related standards are excellent, and following that lead will allow us to reach the correct final conclusions. Somehow we have to retain all of these guidelines. 4.0 Can the measures in PRC-006 be tweaked, and is that even a fix? I believe the direction taken in PRC-006 and PRC-024 is seriously flawed making a discussion of how to tweak and fix things sort of meaningless. That is why I am proposing we adopt “measures” that are based upon the “activities” required to get a safety net in place instead of a measure of “technical details”. However, if we are unable to change directions, then the proposed performance “measures” have to be softened to allow exceptions as based on needs identified in analytical work and to base criteria on actual equipment capabilities. We need a lot of freedom so that groups can make the needed compromises and adopt the right performance criteria. I really don’t think that PRC-006 should be a planning type of standard that tries to micromanage the design process. My opinion is this approach will not ensure reliability objectives are met. We only need to point out the various issues which planning engineers have to consider (this is clearly spelled out in old NERC UFLS standards) and they can take it from there and work through the study process. Planning engineers will understand what needs to be done better than anyone else. Just turn them loose and they will get the job done, and then we will have the UFLS program specifications complete with criteria on how to coordinate with generation protection. The existing NERC UFLS related standards are still highly relevant materials which should be used as guidelines on how to develop load shedding programs. While it is reasonable to start with tentative performance targets as far as design work goes, I consider this as something best left to a study group of the technical experts. Study work has to be performed to find out what is possible before you reach a final decision about what is the best compromise for an UFLS program. In the end, the final program will have to consider if a given area has any unique characteristics that have to be considered, and study work will involve tradeoffs and compromises concerning minimum frequency, maximum frequency, time spent below 60 Hz, and so forth. 4.1 List of specifics related to PRC-006. R1- a group of planning coordinators is not going to be the equivalent of the type of broad based participation we have historically achieved through the NERC Regionals via the existing committee structure. The group concept is a step in the right direction, but the concerns that we can only apply mandatory standards to “legal entities” appears to be leading to artificial constraints that are making it more difficult to achieve the needed coordination and this just makes it more difficult to create the safety net that we want. R2-stresses consistent application across the region, and I would argue that only the final analysis of the system will tell you if this makes sense. There may be subregions which have different needs. In MRO, the Canadian systems have different needs than the US portion of MRO. R3- this says we need criteria on how to select islands. It strikes me as odd that we need “criteria” on how to reach a conclusion. Shouldn’t this just say that analysis shall consider possible system break up patterns that may form islands? For the US portion of MRO, we did not try to say what the most likely island would be. Instead we identified where the break points were, and used this, along with the MRO geographic boundary, to break the system

into pieces. We felt these pieces alone, or aggregated together, represented our possible islands. We evaluated the needs of each of the pieces, and evaluated how to model each piece. We concluded that one set of simulations covering a range of inertia, damping assumptions, and overloads would inherently cover all of these different islanding patterns. So we performed our analysis in a fashion that allowed us to avoid having to make a very specific determination of what the island would be, and instead found a way to make something work in a more global sense. R4-I agree that coordination with neighboring regions is required, but I do not know how to resolve differences of opinion between regions. Perhaps this is nothing to worry about since it is likely to take care of itself. Are we trying to reach a consensus between regions, or just trying to share information and to create a forum for discussion? Obviously where breakups cause islands that straddle different NERC regions, we need to jointly evaluate that island. Even if this coordination is only to share information, it still allows everyone to learn from each other and is going to be quite valuable. R5-is about identifying islands. I think it is the exact wording of this section that bothers me although I agree with the intent. I prefer to focus on break points that may lead to islands. The difference is subtle, but for the US portion of MRO we did not identify “an island”, in the traditional sense, that was the basis for our design. We identified how the grid may break up. We used these break points to break the system down into pockets of load and generation, and then we examined each pocket. These pieces, alone or aggregated together, are our possible islands. We did not try to say which was most likely to form. Some of this represents high unlikely conditions. Some of our parts were not even expected to be islands, and were just the left over parts of the foot print after the obvious break points were identified. The southern and eastern edge of MRO is tightly interconnected and less likely to island, but we still were able to reach a conclusion as to what load shedding level was appropriate for even these areas. We examined load shedding requirements and modeling characteristics of each part. In the end we decided that a 30% load shedding requirement was adequate for each “piece” except for the systems in Saskatchewan and Manitoba. The MRO approach was to allow those regions to have their own programs, so they could satisfy their needs, and we just concentrated on the US portion of MRO. In the US portion of MRO, we found an UFLS program that should work for any of these island patterns as each of the geographic regions we looked at had similar characteristics and load shedding needs. We could model a range of conditions using the equivalent inertia modeling approach and we would inherently capture everything at once. Although our analysis was rigorous, we avoided having to decide on what our island has to be for design purposes, and instead came up with something that is likely to work for about any islanding pattern. With this said I can propose a wording change, I would rather say something like: “…shall identify islanding patterns that can be used as a basis for designing an UFLS program. This shall consider:” R6-addresses the “technical parameters” that I have so much trouble with. I have problems with all of this, as previously discussed at length. I do not like R6.1, R6.2, R6.3 at all, but as part of the study process we would normally come up with parameters of this type after we work through all of the tradeoffs. However I expect we would decide on different technical parameters in the end than is being proposed in PRC-006 and PRC-024. Requirement R6.4, the volts/Hz requirement, does not seem appropriate, and may not have to be addressed at all in an UFLS program. The need to address volts per Hz would depend on how low of a minimum frequency we are expecting. This does not appear to be an issue for programs where the minimum frequency is above 57.2 Hz or so. This might be relevant to isolated hydro systems with large load shedding requirements because hydro systems can accept much lower minimum frequencies than thermal generation (below 57 Hz) and load shedding programs may want to exploit that characteristic. However this would be something that study groups would apply as needed, and does not need to be in a standard. R7-is about the need to do periodic assessments. I agree we need a periodic assessment of some sort. Full blown studies on the other hand are seldom required unless some inherent flaw in an existing program is identified and we need to start with a fresh look at everything. I do not agree with meeting the performance characteristics in R6. We should meet performance characteristics which are defined as a result of the load shedding study process, and not just something that is tossed out up front. I think there are other ways to assess the risk of having units trip off early than just running simulations. This almost implies we have to use full stability cases as our only analytical method. Let engineers figure out how to study the problems using whatever tools, methods, and calculations they feel are appropriate. If we require some assessment of load shedding “need”, then generation which drops off early can be evaluated in terms of how it affects the “needs” assessment, or we can demonstrate how loss of such generation affects programs in a general sense. Personally I feel we should not allow any generation to trip any sooner than prescribed by the final UFLS programs requirement for generation protection settings and delays. On second thought, there will be a few exceptions: units which are unstable like the older wind units, non-utility generation tripped along with load on a feeder as part of UFLS, and perhaps other exceptions where inadvertent tripping cannot be avoided. However, as a general principle, we should not allow any generation to trip prematurely via dedicated under frequency relays unless some offsetting action like tripping additional load can be done. We should not allow generation tripping on overfrequency using dedicated relays (other than tripping actions related to load rejection protection that we do not want to be messing with), unless such overfrequency tripping of generation is a planned activity that is a feature of the UFLS program used to rebalance load and generation. R-8 shouldn’t this database/modeling type of information be compiled as part of the regional model building process? NERC regions do this type of thing today, why is this group of Planning Coordinators getting involved in this. We use the NERC regions to do our coordinating activities, so why depart from what works? I need to understand the reasoning behind this before I can comment further. R-9 appears to say that everyone shall trip load in accordance with the UFLS program. I agree with the intent. 5.0 Appendix I wrote a lengthy document and sent it to NERC when the first draft of this standard was out for comment. As I just emailed that document in directly and did not submit that document through the on-line data forms where comments are provided, my critique did not show up along with all of the other comments. So, I am submitting some of this again as an appendix. Below are the portions of my original document which address the physics of the problem. I imagine some of this has already been discussed above. However, this is still a good review. 5.1 UFLS in Context Before we can really address the Under Frequency Load Shedding Regional Reliability Standard Characteristics document in specific detail, we need to provide a context. Reasonable expectations: * Under frequency load shedding (UFLS) is a one shot, last ditch attempt to save the grid from total collapse for some event that typically far exceeds anything that planning or operating criteria addresses. * Load shedding is inherently a crude and drastic action. * Load shedding has its limits, it can’t protect against everything. * There is no perfect UFLS plan, just lots of different options with lots of different tradeoffs. * In any discussion of UFLS, we need to keep in mind that load shedding might not work as desired in real life, and we can only make it “perfect” on paper, for some tightly defined scenario

subject to a lot of assumptions. * Just about any UFLS program will work great for some overload level, but at a different overload levels it might shed too much and cause a frequency overshoot or shed too little and then frequency might stall out. We can try to minimize such problems, but not totally eliminate them. * Doing "something" to try to quickly correct a major load/generation imbalance is better than doing nothing, and history has shown that load shedding generally works well, but it is not always trouble free. Don't penalize honest efforts to provide a safety net. The best we can do is to eliminate any obvious flaws in the UFLS program design and try to anticipate complications. 5.2 Trade-offs, Compromises, and Uncertainty When it comes to designing a program, engineers find there is considerable uncertainty associated with most every aspect of the problem. Consider: * We do not know what may lead to break up, or necessarily what islands may form or what the final imbalance may be. * There is no perfect way to determine how islands will form, especially if the region is tightly interconnected. Study tools such as stability cases may help identify possible islands, but experience and engineering judgment is perhaps more important. * Factors that affect load shedding performance are not necessarily under the control of the utilities who put in load shedding. * At best, we can bracket a range of unknowns and make educated guesses, and then try to find a program that works as intended, the most often, over the widest range of conditions. * This type of work involves lots of trade offs and compromises. Compromise also applies to simulation methods. No simulation approach is going to be perfectly suited for this type of analysis and each of the standard ways of assessing UFLS has strengths and weaknesses. * Full stability cases are very detailed and good for a very specific spot check, but poor for generalizing. They do not necessarily provide a better way of assessing system performance than a more empirical approach. * Relay application guides typically suggest using the equivalent inertia approach to dynamic modeling where everything is equivalized down into the simplest form that captures the frequency decay dynamics. This simple approach allows rapid prototyping, but it ignores the voltage transients and governor action. To better understand the complications of UFLS design, we need to give a brief statement of the problem: * When we have a mismatch of load and generation, the frequency will decay or increase until we reach a new equilibrium between generation torques and load torques. * If generator power stays constant, then generation torque will increase as frequency drops (power = torque x speed). * Load torques decrease as frequency drops according to the load damping constant. * At some new frequency, we once again reach equilibrium where load and generation torques are equal and this becomes the new synchronous frequency. * Without load shedding we could see frequency decay low enough that generation protection will have to instantly trip generation to prevent excessive loss of life. At that point, the system collapses. Load shedding objective and tradeoffs: * We use UFLS to quickly drive frequency back towards 60 Hz so that we do not risk losing additional generation on underfrequency. * Loadshedding must not cause overfrequency problems that lead to uncontrolled tripping of generation that will precipitate another underfrequency event. * To improve minimum frequency, we can start shedding sooner (higher frequency setpoints), decrease frequency spacing between relay settings, and shed load in fewer blocks of larger size…all of this increases frequency overshoot problems. * We can also improve minimum frequency by deciding to cover a smaller imbalance to begin with. * To decrease frequency overshoot, we can shed load in smaller blocks, increase frequency spacing between relay settings, and use more load shedding blocks in total…all of this decreases the minimum transient frequency for the largest overloads we cover. * Overfrequency based tripping of generation or restoration of load can also minimize frequency overshoot, at the risk of causing the frequency to cycle back into another underfrequency event. * Underfrequency recovery times can be improved by shedding some additional blocks of load on delay, at the expense of increasing the risk of frequency overshoot. The rates of change of frequency and load damping characteristics affect relay coordination: * Large overloads give high rates of change of frequency * Unit inertia represents energy stored in the rotating mass. Inertia (for a given overload level) affects the rate of decay of frequency: high inertia = slower frequency rate of change, low inertia = fast frequency rate of change. * Load damping affects the final frequency where equilibrium is reached. Low damping means larger frequency deviations for a given imbalance. * Generally it is difficult to design a program for low inertia, low damping, high overload conditions. This condition gives the lowest transient frequency, and the fast frequency decline affects relay coordination that can cause overshedding. * Relay coordination is much easier if inertia is high, but recovery back towards 60 Hz will be slower when inertia is high. Let's consider some of the hard to quantify factors that affect performance: * load damping (utilities have no control over the dynamic characteristic of loads, and we are not sure how much damping we have or how it varies in time or by season) * the type of generation on the system * the system inertia on system base (energy stored in rotating mass relative to remaining generation in island) * if asynchronous islands are still being fed by DC lines (this is power with no inertia associated with it, which drives system based inertia down), or if frequency deviations cause DC lines to trip * the magnitude of the imbalance between load and generation * the net governor effect (not much if units are base loaded, running in boiler follow mode, or overridden by power-load controllers) * overvoltages (and how can we moderate voltage deviations)…as load is shed the voltage will swing around, and overvoltages can increase load, offsetting the benefits of load shedding which in turn affects the rate of frequency recovery * random factors, such as unit trips, industrial load trips, additional line outages (including planned separation schemes), and so forth * Wind generation…the older vintage of wind generation will drop off-line as frequency declines…how much will be on-line? * Combustion turbines…they are thermally restricted. Assuming a combustion turbine is operating close to its temperature limit to begin with (i.e. the typical condition when loaded high), the net result is that turbine power drops as frequency starts to decline, aggravating the imbalance. * The actual sequence of events that leads to islanding can have considerable influence on overall performance, yet typically the best we can do in simulations is to form and island all at once by opening all the tie lines at the same moment. This is because we do not get major system breakups from "credible events" that we can easily model. Usually load shedding occurs following a complicated sequence of things going wrong that no one could have ever predicted ahead of time. * Load shedding itself may overload transmission lines, and lead to further system breakup and islanding. * Overshedding can lead to unintended random loss of additional generation in response to overspeed (due to various internal problems at the facility), and cause another cycle into underfrequency from which we might not recover. Now consider future trends: * Industry trends show that load damping is decreasing, and load damping is not precisely known to begin with. Damping also varies in real time. * The trend has been that inertias of new units are lower than in the past. * Some of the newer wind generation provides no inertial effects as rotating mass is decoupled from the electrical grid by the controls that allow variable slip operation of the induction generator or because they are coupled to the AC system through an inverter. * Wind generation is intermittent, difficult to factor into UFLS programs, and with all of the different makes and models out

there, it is difficult to generalize how these units will actually respond and how many will ride through a frequency swing. Different areas have different load shedding needs, and areas that need to shed a lot of load have to make more compromises as far as transient frequency and voltage performance go: * UFLS programs that shed more load will also experience lower minimum frequencies, higher maximum frequencies, and be more prone to relay coordination problems (which increases the chance of overshedding). On the positive side, these programs provide the largest safety net. * Programs which shed the minimum amount of load can use smaller load blocks or fewer load shedding stages which improves frequency response and improves relay coordination over the smaller range of overloads covered. Obviously if overloads exceed the capacity of the program, the system will collapse. In summary, everyone needs to apply common sense and good judgment when dealing with UFLS issues, and compromises have to be carefully considered at every step of the decision process involved with design and implementation.

Individual

Anthony Jablonski

ReliabilityFirst

Yes

No

The Transmision Owner with end use load connected ... is out of line with the NERC Functional Model knowing that if a Transmision Owner has end use load connected, by definition, the Transmision Owner must register as a Distribution Provider. Therefore, using just the Distribution Provider in the UFLS standard is adequate and complete.

No

The Transmision Owner with end use load connected ... is out of line with the NERC Functional Model knowing that if a Transmision Owner has end use load connected, by definition, the Transmision Owner must register as a Distribution Provider. Therefore, using just the Distribution Provider in the UFLS standard is adequate and complete.

Yes

Yes

Yes

Yes

Group

Southern Company

Southern Company Services, Inc.

Yes

Southern Company agrees with the comments submitted by the SERC Region for all questions in this comment form. Submitted SERC responses are essentially replicated in the responses we submit for Southern Company for questions 1-8.
****

We agree that creating a continent wide standard will preserve the intent of utilizing specific expertise within the region to develop UFLS schemes. First of all, this approach will provide uniformity among the regions for developing UFLS schemes, as all the regions will follow consistent performance characteristics specified in the standard. At the same time, the regions will have the flexibility to develop their own requirements to meet their specific needs.

No

No, because the Planning Coordinator(PC) role is implemented differently across the regions. The Transmission Planner(TP) is the most appropriate entity to design the UFLS scheme since the TP has the detailed system knowledge and is generally better positioned to develop the scheme. Also, the Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.

No

The applicability should be assigned to the TO only (not to DP). The Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate, if they choose, to implement the UFLS scheme providing the most selective load tripping, while at the same time, allowing for more efficient aggregation of smaller DPs' load into the overall scheme.

Yes

The generators must be modeled to reflect the way they perform.

Yes

Yes, but with the ability to specify exceptions. Each regional entity should be required to identify the amount of automatic load restoration in their region that is designed to assist in stabilizing system frequency. If the region determines that this amount is insignificant (e.g. 1%) and will not materially impact the design of the region's UFLS

scheme, then they should be allowed to exclude this load from their simulations.
We agree this change better coordinates with PRC-024. If coordination with PRC-024 is the ultimate goal, it seems a simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.).
Yes
No additional comment.
No Comments for Question #7.
--- R8: It is problematic for a loosely organized “group of Planning Coordinators” to create and maintain a database. There are several practical and compliance issues with this. This should be assigned to an entity with clear responsibilities and processes to accomplish the task. Additionally, “annually” and “database” is unnecessarily restrictive given the study is only required on a 5 year basis and in light of existing data collection processes. Recommend revision of R8 as follows: “…shall compile/assemble information provided by their Transmission Owners and Distribution Providers for use in UFLS assessments and event analyses.” Databases should add value and not create extra work that does not directly contribute to the completion of the study. --- R7.1 and R7.2 could have the effect of shifting the generator’s burden of staying on line to the load customer who must be shed to account for the generator’s less-than-expected frequency performance. The generators must be modeled because that is the way they perform, but an exception for frequency support must be difficult for a generator to obtain. --- R10 should say “shall implement the UFLS program” rather than “shall provide load tripping in accordance with the UFLS program” because the phrase “provide load tripping” could be confusing. --- R1 through R8: The concept of PC's joining a group to design a UFLS scheme is flawed. Compliance should never be assessed on a group basis. Each PC (or TP) must be allowed to demonstrate compliance to the standard independently so compliant PCs/TPs are not penalized along with the non-compliant one(s). The standard should be applicable to individual PC's/TPs to design their UFLS scheme to meet the other requirements. The performance characteristics ensure that the schemes from different PC's/TPs will coordinate. However, if a group approach is mandated, then sub-regional groups must be allowed in lieu of regional groups. --- R4 is an unnecessary complication, and should be deleted. A procedure for identifying islands between Regions is not necessary. What if there are no credible islands between Regions? R5 ensures that when credible islands between Regions are identified that all affected entities jointly study UFLS scheme effectiveness within the island. --- R6: Does this requirement say that performance requirements must be met only at a 25% imbalance? Or is it requiring performance requirements to be met at lower imbalances too? If yes, we recommend performing both a 25% and a 15% imbalance test to add clarification. --- R10: Does each DP have to specifically meet the UFLS scheme? For example, if the UFLS scheme is for 30% load in 3 steps of 10% each, some small DP's may not be able to achieve a resolution that fine. Some allowance should be made for aggregating DP's to meet the overall scheme. This allowance should be achieved by making the TO responsible for implementing the UFLS scheme. The TO has a wider area of control and responsibility and is therefore in a better position to coordinate the implementation. --- Unless there is a high bar in PRC-024 to obtain an exception, this passes the responsibility for generators to support frequency on to the loads (to support frequency by shedding). To compensate, this standard needs a requirement for generators which do not coordinate with the R6 requirements to arrange for load to be shed to make up for their generator tripping. --- R7.1: This should not require the modeling trip settings of all generators that trip at or above 58.0 Hz. Since most generators have trip settings for reduced frequency that holds for long periods (e.g. 30 minutes), this would require modeling trip settings of almost all generators. It should only require the modeling trip settings of generators that would trip within the performance envelope defined by R6.1 and R6.2. --- R7.2: This should not require the modeling trip settings of all generators that trip at or below 61.8 Hz. Since most generators have trip settings for higher frequency that hold for long periods (e.g. 30 minutes), this would require modeling trip settings of almost all generators. It should only require the modeling trip settings of generators that would trip within the performance envelope defined by R6.3. --- It is not clear if the standard requires one specific UFLS scheme for the entire Region. One scheme for the Region should not be mandated. Flexibility should be allowed for different schemes within the Region as long as each scheme meets the performance requirements. As a final comment, Southern Company thanks the Underfrequency Load Shedding Standard Drafting Team for its hard work in the development of this continent-wide standard and mapping document. We appreciate the opportunity the drafting team has provided to submit comments on this very important industry matter.
Group
ERCOT ISO
ERCOT ISO
Yes
Yes
ERCOT ISO believes the Planning Coordinator is the correct responsible entity.
Yes
All loads within the region should be accounted for when designing an UFLS program.
Yes
ERCOT ISO believes it is necessary to consider all automatic tripping schemes or protection schemes when designing an UFLS program to meet the requirements of this standard. However, explicit modeling of generator frequency trip settings (above 58.0Hz/below 61.8Hz) should only be required when they are relevant to satisfying the performance requirements of the standard (i.e. if generator trips are initiated for excursions lasting less than 30 seconds).
Yes
At this time ERCOT ISO does not know of any automatic load restoration schemes within the ERCOT Interconnection. But as previously stated in question 3, it is necessary to consider all automatic tripping schemes when developing an UFLS program to meet the requirements of this standard, and therefore ERCOT ISO agrees this is necessary.
Yes

ERCOT ISO agrees that the UFLS program should coordinate with the performance requirements of the Generation Verification Project (PRC-024-1). The requirement for not remaining below 58.2 Hz for greater than four seconds appears to be within the No Trip Zone area of the Off Normal Frequency Capability Curve in Attachment 1 of PRC-024-1.

Yes

ERCOT ISO agrees with the change.

No comment

Comment 1- May need to consider defining the meaning of region (Region) in the NERC Glossary so it is clear for the responsible entities for this standard. Comment 2 – Will it be necessary for ERCOT ISO to have a procedure for coordinating with groups of Planning Coordinators, since we are essentially a group of one? Maybe language could be added to the standard to clarify for this situation. Comment 3 - It would be appropriate for the "load" referenced in the imbalance calculation in requirement R6 to include system (island) losses. The standard should be clearer.

Individual

Bob Thomas, Kevin Wagner, Troy Fodor, Scott Robison

Illinois Municipal Electric Agency

Yes

No

IMEA believes it is not necessary to assign applicability to the TO function since the NERC Statement of Compliance Registry Criteria (Revision 5.0) already specifies that for end-use customers who are served at transmission voltages, the TO also serves as the DP (i.e., such a TO should already be registered as a DP).

IMEA recommends the following language from the Background/Information section of the comment form be included under Section B. Requirements, R2: "…Planning Coordinators may elect to use their Regional Standards Development process to develop the programs (but this is not required) or they may determine that their existing programs fully meet the requirements of this proposed continent wide standard." IMEA believes the standard should only apply to areas where there are required UFLS programs that are in existence and not applied to all load if those loads are already covered in an existing UFLS program. IMEA also recommends that Regional Entities be directed to not include registered functions other than PC, TP, and DP in the applicability section of their region-specific PRC-006 standard.

Individual

Roger Champagne

Hydro-Québec TransÉnergie (HQT)

Yes

No

HQT agree that the Planning Coordinator is the correct Functional Model entity based on having a wide-area view and the planning expertise to perform UFLS assessments. However, it is not clear whether applicability can be assigned to a "group of Planning Coordinators" as opposed to individual Planning Coordinator.

No

Based on the definition of Distribution Provider in the Functional Model we believe that the applicability should be limited to Distribution Providers. All load should be accounted for by a registered Distribution Provider. The standard should not be written to correct for deficiencies resulting from incorrect registration of entities, and proper registration is vital to the reliability of the UFLS program.

Yes

See also our answer to Q8 in regards to the minimum frequency treshold.

Yes

HQT believe that any automatic action that impacts recovery and stabilization of frequency must be modeled.

Yes

HQT believe it is important to remove this apparent miscoordination between the generator tripping requirements in PRC-024 and the UFLS program performance requirements in PRC-006. See also our answer to Q8 in regards to frequency treshold.

No

HQT agree with the intent of the change to focus the concern on buses where V/Hz protection may trip generators rather than broadly applying to all BES buses. However, reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage or generating unit/plant nameplate MVA. We recommend that R6.4 apply to all generator buses and generator step-up (GSU) high-side buses similar to R7.1 and R7.2 applying to all generators that trip at particular frequency tresholds. See also our answer to Q8 in regards to frequency treshold.

HQT recommends that NERC develop standards for unit governing response that are consistent with and support the reliability objectives of standards PRC-006 (UFLS) and PRC-024 (Generator Performance). HQT also notes that it may not be possible for the Planning Coordinators to design a reliable UFLS program that will arrest and recover declining frequency if an excessive number of generators are exempted from meeting the underfrequency performance requirements in PRC-024. HQT, being in the Québec Interconnection, has technical parameters that differ from those specified in Requirements R6 and R7. A Variance will be needed to address those specific concerns in regards to frequency tresholds and parameters.
Individual
Jim Sorrels
AEP
Yes
As each Reliability Coordinator has it's own UFLS requirements, the UFLS programs between the Reliability Coordinator's need to work together.
No
Reliability Coordinators have set up specifics standards on the set points for UFLS. The proposed standard misses this circumstance by not including the Reliability Coordinator in the standard. How would this be reconciled?
Yes
This is a useful method for identifying those TOs where this situation occurs, instead of making the standard unnecessarily apply to all TOs.
Yes
Please note that the reference to R8 in the question appears to an error.
Yes
Please note that we are responding in the context of requirement 7.3, not requirement 9. There appears to be a error in the requirement 9 reference.
Yes
Yes
Wouldn't PRC-006-01 R5 be a SPS with all of it's attendant liabilities. Isn't NERC trying to minimize SPS schemes? PRC-006-01 R5 and EOP 003-1 philosophy would need to agree. PRC-006-01 R5 is written from the standpoint that one is able to predict island formation whereas EOP 003-1 is written to respond to island formation in whatever form it takes by shedding load (EOP 003-1 R6). EOP 003-1's purpose is to protect the interconnection whereas PRC-006-01 R5 would seem to require opening up ties. There seems to be a disconnect here. However, if the UFLSDT does goes forward with this thinking, then AEP would suggest small island formation as likely being more successful than large island formation. Another interpretation of the two standards would be that PRC-006-01 R5 is intended to be designed as an automatic first option. If that option fails, then EOP 003-1 is to be followed by the transmission operator.
Individual
Vladimir Stanisic
Ontario Power Generation
Yes
Yes
Yes
Yes
Yes
Yes
Yes
The SDT should be commended for producing a very good standard. There is one issue however that may negate the outcome of UFLS effort. Maximum permissible frequency overshoot of 61.8 Hz specified in R6.3 appears too high. It would quite likely result in hard to predict loss of many large fossil and nuclear units. Past system disturbances provide enough evidence of such thermal power plant response that typically leads to system collapse. This is a fundamental issue for the design of an effective UFLS scheme. What was the reason for not adopting a lower frequency overshoot value, especially considering that multi-step UFLS schemes should be able to accommodate that?
Individual
Joe Springhetti

We Energies
No
We agree that a continent wide standard should be developed. However, we disagree with the approach taken with this draft of the standard. See our question 8 comments for more detail.
No
See our question 8 comments for more detail.
No
Yes
Yes
Yes
Yes
We are not aware of any conflicts.
We Energies disagrees with the overall approach that the Standard Drafting Team (SDT) has taken with the latest draft of the continent-wide UFLS standard. FERC rejected the original PRC-006 due to its fill-in-the-blank nature. The continent-wide standard is still a fill-in-the-blank standard with the Planning Coordinator (PC) required to fill in the blanks. In addition, the standard does not require the PC to involve the Distribution Provider (DP) and Transmission Owner (TO) in the development of the UFLS program. Also, the standard requires the DP and TO to implement without question whatever UFLS program has been designed by the PC. We are concerned that the standard places a burden on the DP and TO to shed additional load to make up for generators which trip outside of the criteria specified in draft NERC standard PRC-024. A continent wide UFLS standard must set the minimum level of UF tripping for each Interconnection. The continent wide standard must do this by specifying the minimum amount of loadshed, trip frequency steps, and time delay criteria for UFLS relays. The continent wide standard must remain silent on criteria, such as islanding, that is above and beyond the minimum amount of loadshed, trip frequency steps, and time delay criteria. Regional UFLS standards must be the vehicle for going above and beyond the minimum requirements of the continent wide UFLS standard. Islanding is one aspect that can be addressed in regional standards if necessary. If the above comments are not adopted by the SDT, the following additional comments address the standard as written. As mentioned previously, this standard does not have a requirement for the PC to involve the DP and TO in the design of the UFLS program. In addition, the standard requires the DP and TO to implement without question whatever program the PCs design without any concurrence from the DPs and TOs. There must not be any loopholes in this standard which would force the DP or TO to shed additional load for a generator that could meet the criteria specified in draft NERC standard PRC-024. Therefore, R2 must be revised to add a sentence that requires the PC to involve the DP and TO in the design of a mutually agreeable UFLS program. Similarly, R10 must be revised such that it states that the DP and TO will implement the mutually agreed to UFLS program. Lastly, in the RFC region there are only three PCs. This standard is placing a burden and regulatory risk on these three entities in RFC. It is not consensus for three entities to dictate a UFLS program for an entire region. The last sentence of R4 needs two clarifications. First, the text “neighboring entities” needs to be defined. It is unclear if the text “neighboring entities refers to a neighboring PC, DP, TO, GO, Region, etc. Second, the term “assessment” needs to be referenced in a more specific manner. Does the term “assessment” refer to island assessments or the UFLS program assessment required in R7? The last bullet item in R5 needs clarification. First, what is meant by the text “at least one island?” Does this mean the default island is the Region’s electrical boundaries? Second, if a DP or TO’s load is part of multiple islands, what mechanism will prevent the DP or TO being issued conflicting UFLS trip settings (e.g. Island 1 requires the DP to set its relays to trip at 59.0 Hz, while Island 2 requires that same DP to set its relays to trip at 58.7 Hz)? R7.1 and R7.2 need to be revised since as these sub-requirements are currently written all units with automatic UF tripping installed would be required to be simulated. Specifically, R7.1 requires units that trip between 58.0 Hz to positive infinity to be simulated and R7.2 requires units that trip between 61.8 Hz and 0 Hz to be simulated.
Group
PacifiCorp
PacifiCorp
Yes
PacifiCorp believes that the standard language is general enough to allow for regional differences. It is appropriate that the standard addresses “what” the parameters are, not “how” the parameters are to be implemented.
Yes
While PacifiCorp agrees that coordination between Planning Coordinators is necessary in order to design and implement an effective UFLS program, it has some concern regarding the assignment of responsibility for compliance with this standard to a currently undefined “group of Planning Coordinators.” There is no such entity in the Functional Model and it is therefore unclear as to how this group will function and by whom it will be governed. The way the standard is currently drafted raises significant questions regarding how the requirements will be enforced, how a Planning Coordinator will know what “group” to participate in, how its participation in such group will be evaluated, how disagreements between group participants will be resolved, and which entity, among such group of Planning Coordinators, will be responsible for any potential violations. PacifiCorp recommends that either 1) the SDT assign the UFLS coordination responsibility and governance to the Regional Entity; or 2) the SDT re-draft the standard in such a way that allows Planning Coordinators to assign their compliance responsibility and activity to an agent Planning Coordinator Group similar to the group concept utilized in BAL-002-0 that allows Balancing Authorities to

assign compliance responsibility to a Reserve Sharing Group.
Yes
The simulations done by a group of Planning Coordinators must include all load in designing the UFLS program. However, there should be no obligation that all entities be required to shed any of their load at any particular frequency as long as sufficient load is shed in the area under study. The UFLS program could exempt Distribution Providers with peak loads less than an agreed upon threshold from shedding any load as long as sufficient load is shed in the area under study.
Yes
Yes
Yes
Coordination with PRC-024 is very important. PacifiCorp supports this change.
Yes
PacifiCorp concurs with the decision of the SDT drafting team. V/Hz capability is generally associated with generating plants, not all buses within a system.
No comment
No comment.
Group
Electric Market Policy
Dominion Resources Inc.
Yes
Yes
No
The definition of Distribution Provider is adequate.
Yes
Yes
However, Question 4 reference to Requirement R9 should be R7.
Yes
Yes
None
Group
Midwest ISO Stakeholders Standards Collaborators
Midwest ISO
Yes
No
We can understand the assignment of certain responsibilities to a Planning Coordinator. However, attempting to force Planning Coordinators to develop groups and then holding the entire group accountable for one another's compliance is unworkable.
No
We do not believe it is necessary to assign applicability to "Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of the Distribution Provider's load". We believe this clause is describing a distribution provider and these TOs should be registered as DPs. Furthermore, Standards should not attempt to create new classifications of registered entities. This is the function of the compliance registration process.
Yes
Generation owners certainly have the right to set relays to protect their equipment from damage and are actually speeding restoration by doing so. Any units that will trip before frequency triggers UFLS relays should certainly be considered in the dynamic simulations.
Yes
Generally, automatic load restoration is a bad idea. It could interfere with restoration. What if too much load is restored and actually causes frequency to decline significantly?
No
Please provide the technical justification for this performance criterion. We would like to add the statement "Unless generation capability or protection warrants or allows for a lower limit" to the end of the requirement. In the MRO region, this would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load. In these areas, when shedding that much load the frequency would drop below 58.2 Hz for longer than 4 seconds. We understand the SDT wants to ensure load shedding programs achieve quick frequency recovery and minimize

underfrequency exposure. However we do not feel this requirement is the right way to go about that. This type of criteria is overly specific and should not be in the NERC standard. The recently developed MRO UFLS program which sheds 30% of system load appears to meet this criteria, but the Canadian portions of MRO which have higher load shedding requirements are unlikely meet this criteria. Aggressive load shedding programs in general will probably not satisfy this requirement. Frequency recovery, overall load shedding performance, and coordination with generation protection, should all be evaluated at the regional level by those who do the technical analysis of regional load shedding programs. In addition to study work, a lot of common sense needs to be applied. Several things need to be discussed to clarify our position.

No

Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit. This requirement should not be included with this standard because it cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation. The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document. During an under frequency event, generators should be working to pull voltages down anyway. Please see response to question 8 regarding overvoltages related to tripping load without tripping capacitors.

R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria. R2 – We would suggest removing the word "consistent" because the program can not be applied consistently across the MRO Region. The Canadian systems need to shed more load than the US portion of MRO. We need to focus on coordination issues between geographic areas, not on consistent application across a NERC region. Perhaps what was intended is to state that load shedding should be applied uniformly across any island footprint. R4 - Revise text so that the "agreement" between all entities is well documented through several examples: meeting minutes, a formal agreement to work together, results of common drills, examples of coordination of UFLS models, etc.) We would propose that the assessment for non compliance would be located in the formal agreement to work together since all parties should understand the risk or consequences of the group effort. These standards do not appear to consider or address if capacitors should be automatically tripped during UFLS to avoid overvoltage conditions. Do other standards address this or does this draft standard need to be modified?

Group

SERC UFLS Standards Drafting Team

SERC UFLS Standards Drafting Team

Yes

We agree that creating a continent wide standard will preserve the intent of utilizing specific expertise within the region to develop UFLS schemes. First of all, this approach will provide uniformity among the regions for developing UFLS schemes, as all the regions will follow a consistent performance characteristics specified in the standard. At the same time, the regions will have the flexibility to develop their own requirements to meet their specific needs.

No

No, because Planning Coordinator(PC) role is implemented differently across the regions. The Transmission Planner(TP) is the most appropriate entity to design the UFLS scheme since the TP has the detailed system knowledge and is generally better positioned to develop the scheme. Also, the Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.

No

The applicability should be assigned to the TO only (not to DP). The Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.

Yes

he generators must be modeled to reflect the way they perform.

Yes

Yes, but with the ability to specify exceptions. Each regional should be required to identify the amount of automatic load restoration in their region that is design to assist in stabilizing system frequency. If the region determines that this amount is insignificant (e.g. 1%) and will not materially impact the design of the region's UFLS scheme, then they should be allowed to excluded this load from their simulations.

We agree this change better coordinates with PRC-024. If coordination with PRC-024 is the ultimate goal, it seems a simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem

more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.)

Yes

R8: It is problematic for a loosely organized “group of Planning Coordinators” to create and maintain a database. There are several practical and compliance issues with this. This should be assigned to an entity with clear responsibilities and processes to accomplish the task. Additionally, “annually” and “database” is unnecessarily restrictive given the study is only required on a 5 year basis and in light of existing data collection processes. Recommend revision R8 as follows: “…shall compile/assemble information provided by their Transmission Owners and Distribution Providers for use in UFLS assessments and event analyses.” Databases should add value and not create extra work that does not directly contribute to the completion of the study. --- R7.1 and 7.2 could have the effect of shifting the generator’s burden of staying on line to the load customer who must be shed to account for the generator’s less-than-expected frequency performance. The generators must be modeled because that is the way they perform, but an exception for frequency support must be difficult for a generator to obtain. --- R10 should say “shall implement the UFLS program” rather than “shall provide load tripping in accordance with the UFLS program” because the phrase “provide load tripping” could be confusing. --- R1 through R8: The concept of PC's joining a group to design a UFLS scheme is flawed. Compliance should never be assessed on a group basis. Each PC (or TP) must be allowed to demonstrate compliance to the standard independently so compliant PCs/TPs are not penalized along with the non-compliant one(s). The standard should be applicable to individual PC's/TPs to design their UFLS scheme to meet the other requirements. The performance characteristics insure that the schemes from different PC's/TPs will coordinate. However, if a group approach is mandated, then sub-regional groups must be allowed in lieu of regional groups. --- R4 is an unnecessary complication, and should be deleted. A procedure for identifying islands between Regions is not necessary. What if there are no credible islands between Regions? R5 ensures that when credible islands between Regions are identified that all affected entities jointly study UFLS scheme effectiveness within the island. --- R6: Does this requirement say that performance requirements must be met only at a 25% imbalance? Or is it requiring performance requirements to be met at lower imbalances too? If yes, we recommend performing both a 25% and a 15% imbalance test to add clarification. --- R10: Does each DP have to specifically meet the UFLS scheme? For example, if the UFLS scheme is for 30% load in 3 steps of 10% each, some small DP's may not be able to achieve that fine a resolution. Some allowance should be made for aggregating DP's to meet the overall scheme. This allowance should be achieved by making the TO responsible for implementing the UFLS scheme. The TO has a wider area of control and responsibility and is therefore in a better position to coordinate the implementation. --- Unless there is a high bar in PRC-024 to obtain an exception, this passes the responsibility for generators to support frequency on to the loads (to support frequency by shedding). To compensate this standard needs a requirement for generators which do not coordinate with the R6 requirements to arrange for load to be shed to make up for their generator tripping. --- R7.1: This should not require the modeling trip settings of all generators that trip at or above 58.0 Hz. Since most generators have trip settings for reduced frequency that holds for long periods (e.g. 30 minutes), this would require modeling trip settings of almost all generators. It should only require the modeling trip settings of generators that would trip within the performance envelope defined by R6.1 and R6.2. --- R7.2: This should not require the modeling trip settings of all generators that trip at or below 61.8 Hz. Since most generators have trip settings for higher frequency that holds for long periods (e.g. 30 minutes), this would require modeling trip settings of almost all generators. It should only require the modeling trip settings of generators that would trip within the performance envelope defined by R6.3. --- It is not clear if the standard requires one specific UFLS scheme for the entire Region. One scheme for the Region should not be mandated. Flexibility should be allowed for different schemes within the Region as long as each scheme meets the performance requirements.

Individual

Mike Sonnelitter

NextEra Energy Resources, LLC

Yes

No comment.

No comment.

Yes

Yes

Yes

No comment.

No comment.

No comment.

Individual

Jason Shaver

American Transmission Company

Yes

No

We agree with the assignment of selected responsibilities to the Planning Coordinator (PC) and suggest that NERC

revise the Compliance Registry Criteria to add the Planning Coordinator and direct the Regional Entities to register applicable entities to this function. Responsibility for several requirements are assigned to a "group" of Planning Coordinators, but Planning Coordinator Group (PCG) does not appear in the list of applicable entities. We agree with leaving the PCG entity off of the list. However, without a PCG entity in the list, the applicable requirements should be reworded to make each Planing Coordinator individually responsible for their contribution to the group actions. Suggested wording for each applicable requirement is provided in the response to Question 8. If the drafting team decides to apply requirement responsiblities to a PCG, then NERC should revise the Compliance Registry Criteria to add the PSG and direct the Regional Entities to register the applicable entities to this function. Since regional PSGs have not been formed as legal entities in the past, then going this direction would require PC to establish contracts to form these groups in order to clearly define the compliance and sanction liabilities of each PC in the group. Transmission Owners should be removed because it is redundant with Distribution Provider. Per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner that provides and operates the “wires” to end-use Load served at transmission voltages must register as a Distribution Provider or transferred the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. Therefore, we suggest the removal of Transmission Owner from the Applicability section. Generator Owners (GO) should be included in the Applicable entities section and requirements should be added that assign GOs the responsibility for providing generator off nominal frequency protection information to the Planning Coordinator and for coordinating any generator off nominal frequency protection with any applicable UFLS program.

No

As noted in the response to Question 1, per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner with end-use load connected to their facilities must register as a Distribution Provider or transferred the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. So, all applicable end-use load will be covered by the standard and the assignment of applicability to Transmission Owners with end-use load connected to their facilties is superflous and redundant.

No

[This question actually applies to Requirement R7, not R8.] We agree that PCs should model the trip settings of any generators that may be trip during the simulated operation of the UFLS program. The applicable generator trip settings will depend on the set points and time delays of the underfrequency relays in the UFLS program. We suggest that R7.1 be reworded to "that trip at or above the minimum frequency set points and time delays of the applicable island's UFLS program". This approach gives consideration to the time delay aspect and allows the frequency limit to be higher (or lower), if it is permitted by the applicable island's UFLS program. We suggest similar rewording for R7.2, "that trip at or above the maximum frequency set points and time delays of the applicable island's UFLS program". On a related matter, the root Requirement R7 states "conduct a UFLS assessment . . . through dynamic simulations". However, other analytical methods, such as Equivalent Inertia Anaysis, can also be used to perform an appropriate UFLS assessment and may check for proper coordination between the underfrequecy relay settings and the generator trip settings. Therefore, we suggest that the following rewording for R7, "shall conduct a UFLS assessment . . . that determines whether the UFLS program design meets . . . R6. The assessment shall inlcude:" R7.1 "Analysis of the trip settings of any generators that . . ." R7.2 "Analysis of the trip settings of any generators that . . ." R7.3 "Analysis of any automatic load restoration that . . ." See the response to Question 8 for comment on the 58.0 Hz and 61.8 Hz limits.

Yes

[This question actually applies to Requirement R7.3, not R9.] We agree that any automatic load restoration that is designed to assist in stabilizing the system frequency should be modeled in the ULFS Program assessment. On the other hand, we suggest that automatic load restoration should be avoided whenever possible.

No

Please provide the industry with the technical justification for this performance criteria. We would like to add the statement "Unless generation capability or protection warrants or allows for a lower limit" to the end of Requirement R6.2 and R6.3. In the MRO region, this qualification would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load to achieve reasonable frequency recovery in these islands. In these areas, the shedding this quantity of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generators in these islands are acceptable.

No

Please provide the industry with the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a generator unit. This requirement should not be included with this standard because it cannot be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation. The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000)) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document.

ATC believes that the SDT should develop official definitions for the following three terms used throughout the document: a) "under-frequency load shedding" (along with “under-frequency load shedding program”) b) “island” and “region”. All three terms warrant a definition in order to be able to assess whether the plans developed pursuant to the standards are consistent between and among the Planning Coordinators. Although these terms may have some generally accepted meaning, there likely is a difference among Planning Coordinators and those differences could potentially lead to enforcement issues. The failure to define these terms by NERC will result in each Planning Coordinator providing their individual perspective that could result in either gaps in the “region” or difference in what is meant by an “island” within a region, and what constitutes an “under-frequency load shedding program”. R2 – To

make the requirement apply to each PC rather than a group, we suggest this rewording, “Each Planning Coordinator shall design . . . that was developed in coordination with the applicable regional group(s)”. R2 - To allow appropriate UFLS program differences amoung islands within a single Regional Entity, we suggest this rewording, " . . . under frequency load shedding programs for consistent application across each island within the Region." Some islands in the MRO need to shed more load than other to achieve reasonable frequency recovery. R3 – To make the requirement apply to each PC rather than a group, we suggest this rewording, “Each Planning Coordinator shall develop . . . in coordination with the applicable regional group(s) to apply to select portions of the Bulk Electric System that are designated as islands”. R4 – To make the requirement apply to each PC rather than a group and include corordination within the Region, we suggest this rewording, “Each Planning Coordinator shall develop a procedure for coordinating with groups of Planning Coordinators within its Region(s) and groups of Planning Coordinators in neighboring regions . . .” R5 – To make the requirement apply to each PC rather than a group, we suggest this rewording, “Each Planning Coordinator shall identify . . . as a basis for designing a UFLS program with the applicable regional group(s)”. R6 – To make the requirement apply to each PC rather than a group, we suggest this rewording, “Each Planning Coordinator shall specify . . . load shedding program in coordination with the applicable regional group(s) that are required to meet the following . . .” R6.1 – To match the design emphasis that is included in R6.2 and R6.3, we suggest “. . . no less that 58.0 Hz per simulated event.” R7 – To make the requirement apply to each PC rather than a group, we suggest this rewording, “Each Planning Coordinator shall conduct . . . with its applicable regional group(s)”. R8 – To make the requirement apply to each PC rather than a group, we suggest this rewording, “Each Planning Coordinator shall create . . . in coordination with its applicable regional group(s) . . .” R8 - Since the interpretation of "annually" can vary widely, we suggest this rewording, "each calendar year and within 15 months of the last update". R9 – Since the Transmission Owner reference is redundant, we suggest this rewording, “Each Distribution Provider shall provide. . .”. R10 – Since the Transmission Owner reference is redundant, we suggest this rewording “Each Distribution Provider shall provide . . .” R11 - Since reactive power device overvoltage or underfrequency protection may be essential to the UFLS program assessment, we suggest adding the Requirement, "R11. Each Distribution Provider and Transmission Owner shall provide its reactive power device overvoltage or underfrequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section. R12 - Since reactive power device overvoltage or underfrequency protection may be essential to the UFLS program design, we suggest adding the Requirement, "R12. Each Distribution Provider and Transmission Owner shall reactive power device tripping in accordance with the UFLS program desinged by the group of Planning Coordinator for each region in which they operate." R13 - Since generator off nominal frequency protection information may be essential to the UFLS program assessment, we suggest adding the Requirement, "R13. Each Generator Owner shall provide its off nominal frequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators." R14 - Since the coordination of generator off nominal frequency protection is essential to the UFLS program design, we suggest adding this Requirement "R14. Each Generator Owner shall have evidence that they provided any coordination that is required by the applicable regional group of Planning Coordinators to meet UFLS program specifications." Reference Document - Due the number and complexity of the elements that need to be considered to develop effective UFLS program designs and for fulfilling the requirements in this standard (e.g. island identification, number of load tripping steps, frequency settings, time delays, percentage of load per step, system inertia, governor response, etc.), we suggest that a reference document be developed to provide useful information regarding automatic UFLS programs to the applicable entities.

Group

FRCC Standards & Operations Departments

Florida Reliability Coordinating Council

Yes

We agree with the concept of the development of a Regional UFLS program that conforms to the common performance characteristics contained in the draft standard; however it is not clear what constitutes a 'region'. The SDT has repeatedly used the capitalized version ('Region') of the word in all of the associated documents (i.e. background, comment form) and reverted back to lower case version (region) in the standard. We believe that 'region' should be defined in the standard and incorporated into the NERC Glossary of Terms. This will ensure that the appropriate scope is applied in the development of Regional UFLS programs.

No

Although we agree with the concept of the coordinated effort to design an underfrequency load shedding program, we believe that there is a need to establish an entity with the overall responsibility of coordinating the efforts of the Planning Coordinators. We recommend that the Regional Entity be responsible for overseeing the development of the Regional UFLS program while requiring the Planning Coordinators to participate in the process. Although the provided background material dismisses the idea of expanding the applicability to include the Regional Entity, the precedent has been established by assigning applicability to the Regional Entity in the CIP standards.

Yes

We believe that it is necessary to assign applicability to 'Load Serving Entities'. The Compliance Registry Criteria states: “Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system”. Therefore their applicability is appropriate. In addition we recommend adding a caveat within the applicability section that reads “The TO, LSE or DP may meet these requirements through participation in an aggregated UFLS Program as permitted by the Regional UFLS program.” This would allow smaller systems to aggregate load requirements and more effectively meet Regional UFLS requirements. Furthermore, we recommend an additional caveat within the applicability section that reads, "Compliance with an approved Regional Reliability Standard which defines the requirements of the Regional UFLS program satisfies the compliance requirements associated with this continent wide standard." This assumption can be made based on the defined attributes of a Regional Reliability Standard (i. e. Regional Reliability Standards go beyond, add detail to, or implement NERC Reliability Standards. Regional Reliability Standards shall not be inconsistent with or less stringent than NERC

Reliability Standards.).
Yes
Yes
Yes
Yes
We appreciate the Drafting Teams efforts on this very difficult standard and would offer the following suggested clarifications: R8. Each group of Planning Coordinators shall create and annually maintain a UFLS database containing relay information provided by their Transmission Owners and Distribution Providers for use in UFLS assessments and event analyses. Suggest rewording R8 as follow: R8. Each group of Planning Coordinators shall maintain a UFLS database which identifies the participating Planning Coordinators, contributing entities and contains information (as defined in R9) provided by their Transmission Owners, Distribution Providers and Load Serving Entities for use in UFLS assessments and event analyses. Suggest adding Load Serving Entities to R9. R10. Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates. Suggest rewording R10 as follows: Each Transmission Owner, Distribution Provider and Load Serving Entity shall provide forecast load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates.
Individual
Rick Terrill
Luminant Power
Yes
Yes
Yes
Yes
Luminant agrees with the UFLS SDT that the Planning Coordinators should model the generators that would trip at or above 58.0 Hz, as required by R7. However, Requirement R8 of PRC-006 requires the Planning Coordinator to maintain a database of relay information only from Transmission Owners and Distribution Providers. The Planning Coordinator database in Requirement R8 should also include relay information from Generator Owners. The UFLS SDT does not need to include a requirement in PRC-006 for Generator Owners to provide the information, as the draft NERC Standard PRC-024 requires Generator Owners to provide frequency and voltage relay setting information to the Planning Coordinator.
Yes
Yes
Yes
Luminant agrees with the direction of the UFLS SDT. Luminant further requests that the drafting team modify Requirement R6.4 to clarify that the per unit V/Hz limits modeled are 1.18 and 1.10 of “Nominal” transmission system voltage.
None
Several of the requirements are for a “group” of Planning Coordinators. From a Compliance perspective, how will the actual requirements be enforced on the group, or will the requirements be enforced on each individual Planning Coordinator?
Individual
Kirit Shah
Ameren
No
It seems that regional standards with continent-wide performance characteristics would be the best mechanism to achieve this purpose. The only reason to have a continent wide standard to is to subscribe to the NERC process. There seems to be more focus on the process than the ultimate goal.
No
It seems that the Transmission Planner would be a better choice than the Planning Coordinator for the design of the UFLS programs. The Transmission Planner is more knowledgeable about the how the load and generation interact and how best to model these impacts on the frequency.
Yes
There may be loads that have no association or relationship with a “Distribution Provider” that would allow their load to be interrupted and thus be considered for the UFLS program.
Yes

Yes, such generators should have their trip settings modeled to determine the additional load that must be shed because they do not meet performance characteristics. The cost to include this additional load shed should be allocated to these generators.
No
Each region should be required to identify the amount of automatic load restoration in their region that is designed to assist in stabilizing system frequency. If the region determines that this amount is insignificant and will not materially impact the design of the region's UFLS program, then they should be allowed to exclude this load from their simulations.
Yes
It is a step in the right direction but additional modifications to the performance characteristics are needed to coordinate effectively with PRC-024. When viewing the frequency and time limits in PRC-024 simultaneously with this draft standard in a graphical manner, there are regions of frequency and time duration for which it is permitted for the generators to operate, but for which it is not permitted for the system as a whole to operate.
Yes
It is an improvement over the previous draft. However, there are still questions as to whether this requirement is needed. Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit. This requirement should not be included with this standard because it cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation.
No
There is nothing in the standard that provides direction in terms of measuring whether an entity has effectively implemented a UFLS program.
Group
Florida Municipal Power Agency and Select Members
Florida Municipal Power Agency
Yes
No
While we agree that the responsibility resides with a regional planning coordinator type of Entity, a "group of Planning Coordinators" is a somewhat nebulous term and calls into question the enforceability of the standard, and therefore calls into question whether FERC will approve it or not. If the group of Planning Coordinators is noncompliant, who is noncompliant? Who negotiates settlement? Who would pay a potential fine? If one of the Entities does not provide data for the database required in R8, are all of the PCs noncompliant? As with nearly all things, in order to get something done, leadership is necessary, so, although this is certainly a team effort, one Entity ought to be designated to offer that leadership. Why not keep it the Regional Entity? Alternatively, is there sufficient justification to create a new function called the Regional Planning Coordinator? Or to change the definitions of Planning Coordinator, Transmission Planner and Resource Planner to essentially cause Transmission Planners and Resource Planners to focus on more local issues whereas the Planning Coordinator by definition becomes regional (and hence eliminates the need for the term a "group of Planning Coordinators")?
Yes
Yes, we agree, but, want to be sure the implications are understood. As written, it would seem that the proposed language would make Transmission Owners responsible for adding up the load connected to their system, and if the total load scheduled to trip by UFLS does not meet the percentage of total load connected to that TO required, then, the TO would seem to be the ones responsible for making up the difference. We have to call into question whether capturing all of the load is worth the effort and whether it truly makes a significant difference to the reliability of the Bulk Electric System. We would suggest the added flexibility of including Load Serving Entities (LSEs) to the applicability section as well as including the ability for LSEs to represent multiple Distribution Providers. The Compliance Registry Criteria states: "Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system". Therefore their applicability is appropriate. In addition we recommend adding the ability to aggregate within the applicability section that reads "The LSE or DP may meet these requirements through participation in an aggregated UFLS Program." This would allow small systems to aggregate load requirements and more effectively meet Regional UFLS forecast load tripping requirements. The aggregation provides better resolution to the Regional plan requirements. Or alternatively, create a new function that allows aggregation similar to a Reserve Sharing Group.
Yes
Yes
Yes
Yes
Group
MRO NERC Standards Review Subcommittee
MRO

Yes
No
We agree with the assignment of selected responsibilities to the Planning Coordinator (PC) and suggest that the NERC Compliance Registry Criteria be revised to add the Planning Coordinator function and the Regional Entities be directed to register applicable entities to this function. Responsibility for several requirements are assigned to a "group" of Planning Coordinators. However, these groups do not presently exist and are not registered or legal entities. Perhaps a Planning Coordinator Group (PCG) should be added to the Applicability section and the NERC Compliance Registry Criteria be revised to add the PCG function, similar to the Reserve Sharing Group (RSG) function. Then, Regional Entities might be directed to register applicable entities to this function. Establishing PCGs would help PCs clarify how the group's responsibilities for compliance and liabilities would be assigned to each of its members. If a registered PCG function is not established, then drafting team should revise R1 to require all Planning Coordinators in a region to form a joint agreement to cover fulfillment of the subsequent UFLS requirements. See details in response to question 8. Transmission Owners function should be removed because it is unnecessary and redundant with the Distribution Provider function. Per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner that provides and operates the “wires” to end-use Load served at transmission voltages must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. However, the TO function should be retained if SDT adopts the suggestion of adding R11 and R12 reguarding reactive power devices (in Q8). Generator Owners should be assigned responsibility for coordinating any generator off nominal frequency protection with any applicable UFLS relaying and for providing generator off nominal frequency protection information to the Planning Coordinator. So, the Generator Owner function should be added to the Applicability section. The SDT should coordinate with PRC-024 so that requirements do not overlap.
No
The MRO NSRS believes that the definition of Distribution Provider assures that there are no gaps or holes in coverage of the applicable load. As noted in the response to Question 1, it is unnecessary to also assign applicability to Transmission Owners with end-use Load connected to their Facilities because according to the NERC Compliance Registry Criteria Rev 5.0 (Sections II.b and III.b.2) these entities must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement.
No
[This question actually applies to Requirement R7, not R8.] We agree that PCs should model the trip settings of any generators that may be tripped during the simulated operation of the UFLS program. However, the applicable generator trip settings may vary depending on the set points and time delays of the underfrequency relays of the UFLS program for a given island. We suggest that R7.1 be reworded to "that trip at or above the minimum frequency set points and time delays of the applicable island's UFLS program". This approach gives consideration to the time delay aspect and allows the frequency limit to be higher (or lower), if it is permitted by the applicable island's UFLS program. We suggest similar rewording for R7.2, "that trip at or above the maximum frequency set points and time delays of the applicable island's UFLS program". On a related matter, the existing Requirement R7 states "conduct a UFLS assessment . . . through dynamic simulations". Therefore, we suggest that the following rewording for R7, "shall conduct a UFLS assessment . . . that determines whether the UFLS program design meets . . . R6. The assessment shall include: " This would allow other analytical methods, such as the Equivalent Inertia Analysis, to be used to perform an appropriate UFLS assessment. The Equivalent Inertia method can also be used to check for proper coordination between the underfrequecy relay settings and the generator trip settings. R7.1 "Analysis of the trip settings of any generators that . . ." R7.2 "Analysis of the trip settings of any generators that . . ." R7.3 "Analysis of any automatic load restoration that . . ." See response to comment 8 regarding the 58 Hz limit.
Yes
This question actually applies to Requirement R7.3, not R9.] We agree that any automatic load restoration that is designed to assist in stabilizing the system frequency should be modeled in the ULFS Program assessment.
No
Please provide the technical justification for this performance criteria. We suggest the addition of the statement "Unless generation capability or protection warrants or allows for a lower limit" to the end of Requirement R6.2. In the MRO region, this qualification would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load to achieve reasonable frequency recovery in these islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable. On a related note, we suggest the addition of the statement "Unless generation capability or protection warrants or allows for a higher limit" to the end of Requirement R6.3, if the impacts of island equipment are acceptable.
No
Please provide the technical justification for this performance criteria. We are unaware of any UFLS event where V/Hz protection tripped a generator unit. This requirement should not be included with this standard because it cannot be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation. The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document.
R1 - Reword the requirement to state the Planning Coordinators within a region shall have an agreement with all the Planning Coordinators rather than creating a new group. (For example similar to agreement requirements between

BAs in EOP-001, between GOs and transmission entites in NUC-001, and RCs to form an agreement in IRO-001 R7.) Proposed wording for R1: "Planning Coordinators shall have agreements with all Planning Coordinators in the region, that shall, at a minimum, contain provisions for cover fulfillment of the subsequent UFLS requirements in the standard." This agreement would clarify how "group" responsibilites for compliance and penalties would be assigned to its member entities. For example, would all Planning Coordinators be non-compliant, if one or more members of the group is non-compliant or if a group could not come to consensus on elements needed to fullfill a requirement? Would the financial penalty be shared among the group or would each member be assessed separate penalties? R2 – We suggest the following revised wording, "shall design a load shedding program or multiple load shedding programs so that all areas of the region are covered." In the MRO, the Canadian portions of the system need to shed more load than the U.S. portion of the system. There needs to be coordination within each potential island, but not necessarily consistent across each, entire NERC region. Perhaps what was intended is to state that load shedding should be applied uniformly across an island footprint. R4 - Revise text so that the "agreement" between all entities is well documented through several examples: meeting minutes, a formal agreement to work together, results of common drills, examples of coordination of UFLS models, etc.) We would propose that the assessment for non-compliance would be located in the formal agreement to work together since all parties should understand the risk or consequences of the group effort. R6.1 – To match the design emphasis that is included in R6.2 and R6.3, we suggest ". . . no less that 58.0 Hz per simulated event." R8 - Since the interpretation of "annually" can vary widely, we suggest this rewording, "each calendar year and within 15 months of the last update". R9 – If the inclusion of Transmission Owner is determined to be redundant, reword to, "Each Distribution Provider shall provide. . .", as noted in response to Q1.b. R10 – If the inclusion of Transmission Owner is determined to be redundant, reword to, "Each Distribution Provider shall provide . . .", as noted in repsonse to Q1.b. add R11 - Since reactive power device overvoltage or underfrequency protection may be included to the UFLS program assessment, we suggest adding the Requirement, "R11. Each Distribution Provider and Transmission Owner shall provide its reactive power device overvoltage or underfrequency protection information in the format and according to the schedule specified by the applicable Planning Coordinator." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section.] add R12 - Since reactive power device overvoltage or underfrequency protection should be included in the UFLS program design for a specific island, we suggest adding the Requirement, "R12. Each Distribution Provider and Transmission Owner shall provide reactive power device tripping in accordance with the UFLS program designed by the applicable Planning Coordinator for each region in which they operate." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section.] add R13 - Since generator off nominal frequency protection information may be included to the UFLS program assessment, we suggest adding the Requirement, "R13. Each Generator Owner shall provide its off nominal frequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators." add R14 - Since the coordination of generator off nominal frequency protection should be included to the UFLS program design for a specific island, we suggest adding this Requirement "R14. Each Generator Owner shall have evidence that they provided any coordination that is required by the applicable regional group of Planning Coordinators to meet UFLS program specifications." It is not clear if the standard requires one specific UFLS scheme for the entire Region. One scheme for the Region should not be mandated. Flexibility should be allowed for different schemes within the Region as long as each scheme meets the performance characteristics. Below is a list of technical requirements or issues the MRO NSRS would like the UFLS DT to consider for either a reference document or for regional variences. A. Limited Number of Island Loads - What allowance should made for Distribution Providers with a limited number of loads in a designated island? B. 58 Hz Limit - Consideration should be given to circumstances in some islands where a lower frequency limit would allow better UFLS program performance. For instance the the Canadian example mentioned above. C. Coordination with the Proposed PRC-024 Standard - Consideration should be given for proper coordination for of this standard (UFLS) with the PRC-024 standard especially with reguard to off-nominal frequency settings for generation. D. Reference Document - We think it would be valuable to develop a companion reference document that may contain the following expectations and intentions: - The intent of this standard is to ensure UFLS programs are effective, and to the extent possible, that potential problems have been addressed in the design phase. - This standard should achieve an appropriate level of reliability and not just the least common denominator. An evaluation should be made to determine if the minimum load shedding requirement is sufficient and appropriate for a given geographic region. Although no geographic region (potential island) is obligated to exceed the minimum load shedding requirement, load shedding beyond the minumum requirement is encouraged when there is an identified advantage of doing so. - Overall coordination issues are easier to satisfy for programs that shed the minimum amount of load. Such programs will be better behaved over the smaller range of overloads, but the system will collapse if loss of generation (or import) exceeds the amount of load shed. Larger, more aggressive load shedding programs will provide a larger safety net at the expense of wider voltage and frequency deviations, and generation in those areas will need to accept more off-nominal frequency exposure to achieve coordination with load shedding. - UFLS analysis has to deal with considerable uncertainty in a multitude of variables. It is assumed that conflicting performance requirements and tradeoffs will be documented and resolved through application of engineering judgment. - This standard acknowledges that performance measures such as frequency and voltage deviation are subjective. Both voltage and frequency are influenced by hard-to-quantify factors that vary in real time, such as load damping, the net governor response, and inertia of spinning on-line units. Such performance measures can only be applied in consistent fashion to a tightly defined set of qualifying assumptions. - This standard acknowledges that UFLS is basically a last ditch effort to prevent system collapse and that it has limits. It is not possible to achieve desired performance for all of the unlikely events that may occur in real life. - Performance characteristics given in this standard should be treated as design targets or design guidelines. Studies run to develop UFLS programs may indicate different design criteria is appropriate as part of the overall compromise that has to be struck between performance and the level of load shedding coverage that is desired. - There is no perfect tool for studying UFLS, and this standard is not meant to prescribe any particular engineering approach to system analysis and review of UFLS performance. For example, the equivalent inertia method allows for sensitivity analysis and broader insight into the frequency decay dynamics. Likewise, the full transient stability case is more useful for simulating actual disturbance conditions including voltage transients.

Group

Kansas City Power & Light
Kansas City Power & Light
Yes
No
It is unnecessary to designate a Transmission Provider with end-use load. That is a Distribution Provider. Generator Owners should be added since generator data will be required to be provided for modeling purposes.
No
No, it is not necessary to include Transmission Provider with end-use load.
No
This question is actually referring to requirement R6. What is the engineering basis for 58Hz? The frequency threshold should be based on the prevention of damage to generating equipment, operating equipment, customer loads, etc. Regardless of frequency threshold, all generator protection settings that involve frequency and voltage should be modeled in the simulation studies for UFLS programs.
Yes
No
Do not have a problem with a frequency threshold or duration, however, 58.2Hz and 4 seconds sounds arbitrary. UFLS systems have been in place for years and would be very difficult and expensive to modify to meet the criteria stated here. To justify any need to go to that expense, it is important to establish the engineering basis for this criteria. What is the engineering basis for the 58.2Hz and 4 seconds?
No
Do not agree with requirement R6.4 regarding the criteria for ensuring control voltage at the generator does not exceed 1.18 V/Hz for a duration longer than 2 seconds. The operating boundaries and control schemes at the generators are in place for the protection and reliable operation of the generator and should be modeled as they are and UFLS design should be modeled around the generator in the attempt to maintain generator connection to the grid.
Not aware of any conflicts.
1. What is the engineering basis for any of the boundary and threshold criteria established by requirement 6 and its sub-requirements? These prescribed requirements may not fit with already established UFLS systems and to justify the expense of changes there should be a sound engineering basis for doing so. 2. R9 requires Transmission Owners and Distribution Providers according to a schedule and format specified by the Planning Coordinator, but does not require Generator Owners to provide generator protection information. Recommend the SDT consider the inclusion of generator information in the appropriate places in these requirements.
Individual
Doug Hohlbaugh
FirstEnergy Corp
Yes
No
We support the removal of the “Transmission Owner with end-use Load connected to their Facilities …”. The Distribution Provider entity adequately covers all load that is subject to this standard. The Generator Owner should be added to better coordinate their frequency protection with UFLS.
No
The Distribution Provider sufficiently covers the end-use load subject to UFLS requirements and we do not believe the Transmission Owner needs to be included within the applicability of this standard.
No
The Planning Coordinator should be required to model somewhat below the 58.0 Hz level, we suggest down to 57.5 Hz, so that a sensitivity analysis is performed evaluating the severity of frequency disturbance that is not fully arrested at or above the 58 Hz level. This information could be used to assess if additional load dropping may be needed for more severe frequency events.
Yes
No
The requirement does not exactly match those in PRC-024-1 (Attachment 1) on generator frequency characteristics. In fact, reliability would be better served if the frequency requirements for generators was in PRC-006 rather than PRC-024. For UFLS to be effective, it is a fundamental concept that generation stay connected long enough for load shedding to fully occur. By separating these requirements into different standards, it discounts the need to balance load and generation in a stressed system. PRC-024 allows GO's to be granted exceptions to meeting a fairly generous frequency characteristic but there are no assurances that an equivalent load is shed to balance these exceptions.
No
The requirement has been devised to protect generators and step-up transformers from over-excitation based on traditional protection guidelines. However, other elements in the BES can also become over-excited. Dynamic simulations look at many quantities such as voltage and frequency but Volts/Frequency is not a common output that is reviewed. It is suggested that it would be better to require that bulk capacitors be tripped if system voltage exceeds equipment limits.

We are not aware of any conflicts.

1) On requirement R7.1 we suggest adding the words “under-frequency” before the phrase “trip settings” for clarity. 2) On requirement R7.2 we suggest adding the words “over-frequency” before the phrase “trip settings” for clarity. 3) As stated in question 5, the frequency requirements for generators should be in this standard PRC-006 not PRC-024. 4) The new standard does not properly address the requirements of PRC-009 to analyze the performance of an UFLS program following an under frequency event. If the standard is retire PRC-009, it needs to properly cover the analysis of these events and not refer them to ERO Rules of Procedures. Since PRC-004 covers the analysis of System Protection misoperations and PRC-016 covers SPS misoperations, UFLS events including misoperations also must be covered in a standard to ensure review. 5) On requirement R.1 the use of the word “region” should be replaced with “Regional Enity territory” for clarity so that region may not be misinterpreted to be RTO region or some other sub-region of a Regional Entity territory. We suggest the requirement be written to say “Each Planning Coordinator shall join a group consisting of all Planning Coordinators within the Regional Entity territory it performs the Planning Coordinator function.” 6) We support the following MISO comment. “R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria.”

Individual

Armin Klusman

CenterPoint Energy

No

For many years, CenterPoint Energy has complied with regional UFLS criteria for distribution load tripping. CenterPoint Energy does not believe it is necessary to include any requirements within PRC-006 for applicability to Transmission Owners and, therefore, recommends deleting Transmission Owner from Requirements 9 and 10. CenterPoint Energy commends the SDT for addressing the difficult issue of Applicability. By definition, Transmission Owners do not serve any load, whether distribution voltage or end-use transmission voltage. There may also be legalities that can preclude a Transmission Owner from serving any load. It would be problematic for a Transmission Owner to determine what transmission end-use load to trip when such loads can be refineries, chemical plants, water plants, and national space agency facilities. Tripping of such loads may have environmental and safety impacts. In addition, a Transmission Owner may not have any ownership of a transmission voltage end-use facility, nor control over such a facility. CenterPoint Energy believes the NERC Functional Model correctly reflects that Distribution Providers, not Transmission Owners, would be the responsible entity for load tripping.

1. CenterPoint Energy again commends the SDT for addressing the difficult issue of Applicability. CenterPoint Energy suggests the SDT also address the difficult issue of placing requirements within the proper category of reliability standard. CenterPoint Energy recommends placing Requirement 9, dealing with submittal of UFLS data, within a MOD standard (Modeling, Data, and Analysis). CenterPoint Energy believes the UFLS data will be used for modeling to facilitate dynamic simulation studies and, therefore, should be included in an MOD standard. 2. CenterPoint Energy appreciates the SDT’s attempt to clarify islanding. However, the SDT may have misinterpreted CenterPoint Energy’s comments on Draft 1. Reiterating our comment, CenterPoint Energy believes regional and/or predetermined islanding is not always applicable in an interconnection-wide region. In addition, the requirements dealing with “a group of Planning Coordinators” are also not applicable to an interconnection-wide region, such as WECC and ERCOT. With eight of the ten proposed requirements applicable to “a group of Planning Coordinators”, it appears eight requirements will be problematic for WECC and ERCOT. CenterPoint Energy recommends the following wording be included in Requirements 1 through 8: ‘This requirement is not applicable in an interconnection-wide region’.

Individual

Dan Rochester

Independent Electricity System Operator

No

Further, we propose the scope of the standard be revised to clearly indicate that it focuses on the global events, as follows: To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following widespread underfrequency events.

No

We do not agree with the SDT to remove the Regional Entities from being assigned requirements on the basis that: “… the Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements.” There are a number of existing standards, for examples: CIP standards, BAL-002, EOP-004, EOP-007, FAC-013, FAC-012, to name a few, that hold the Regional Entities (Regional Reliability Organizations, as written) responsible for standard requirements. Unless and until an assessment is conducted to conclude that all such requirements can be replaced with an alternative responsible entity(ies), we do not see a problem with the Regional Entities being held responsible for complying with standards. The way the requirements are assigned in this draft standard (“each group of Planning Coordinators shall”) leaves room for confusion to the industry and debates in the compliance audit process. Unless the “Group of PCs” is registered as an entity, we are

unable to see how the pertinent requirements can be legally enforced. An alternative is to assign these requirements to the Regional Entities, OR, develop a requirement for each PC to have an agreement with its Regional Entity to engage in the design of a UFLS program and coordinate settings with other PCs' programs to achieve consistent application across the region. This way, the requirements can be written to hold "Each Planning Coordinator" rather than "Each group of Planning Coordinators". If this approach is adopted, R1 and R2 could be combined as follows: R1. Each Planning Coordinator shall have an agreement with its Regional Entity to participate with other Planning Coordinators within the region in coordinating the design of an underfrequency load shedding program for consistent application across the region. With this change, R3 may be combined with R1 or be a separate requirement holding each PC responsible for engaging in the development of the criteria. And R3 to R8 can be revised to "Each Planning Coordinator, in meeting the intent of R1, shall…" The proposed changes provide clarity to the PC's responsibility and removes gray areas in the compliance audit process.

Yes

We agree that it is necessary to assign applicability to Transmission Owners with end-use Load connected to their facilities where such end-use load is not part of a Distribution Provider's load. This assignment is in principle consistent with the perceived process presented in the Functional Model pertaining to the Transmission Operator having a role to curtail loads that are under its control to relieve transmission constraint. Excerpt from Chapter 14 of the Version 4 Functional Model – Technical Document, below, describes this process: [When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedence of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.] Loads that are connected to the transmission facilities and where such loads are not part of the DP's loads can and should be curtailed by the TOP action (to relieve constraints) or by the UFLS relays provided by the TOs (to arrest frequency decline).

Yes

We agree but I think you meant R7, not R8. And assuming that the expected loss of generation (for generators tripping at or above 58.0 Hz) is to be compensated by selecting an additional, equivalent amount of load in the UFLS program, the additional load reduction would also need to be simulated. If this requirement is to be added, depending on how this is to be complied with the Applicability Section may need to be expanded.

Yes

Again, we think you meant R7, not R9. We agree. Any pre-determined actions such as tripping of additional load for generator tripping at or above 58.0 Hz as discussed in Q3, above, and automatic restoration of load, etc. should be modeled and assessed via simulations to evaluate frequency performance of potential islands.

Yes

We do not have a concern with this requirement if the 0.2 Hz above 58.0 Hz is intended as a margin/buffer to ensure generators do not trip pre-maturely. However, we do have a concern with R6.3. During the 2003 blackout, the overfrequency limits in R6.3 were violated without any reported adverse effects on the BES. Why are the overfrequency limits needed? If they are not needed to protection equipment, then they should be removed.

No

The 20 MVA/unit and 75 MVA per generating plant/facility thresholds are the same as those presented in PRC-024, on which we expressed a disagreement. In an islanded situation, each generator's status is critical to ensuring frequency decline is successfully arrested based on the assumption that all on-line generators would not trip within specific frequency bounds unless prior approval has been sought and granted to allow tripping. Not limiting the potential for overexcitation (V/Hz) at the smaller generators/plants exposes the island to a great uncertainty on the amount of generation that can be relied upon to arrest frequency excursion.

None

(1) We propose R5 to be expanded to require the Planning Coordinators to develop criteria for identifying potential islands, as follows: Each Planning Coordinator shall develop criteria, considering historical events and system studies, to select portions of the Bulk Electric System (BES) that can form an island(s) as a basis for designing a UFLS program. The identified island(s) shall include: …. (2) R6 needs to be more precise regarding load. Suppose a station with 100MW of load has 20MW of distributed generation added that is anticipated to be in service during the ULFS calculation period (e.g. summer peak hour). Is the ULFS arming determined on basis of 100MW or 80MW of load? This will make a big difference in Ontario if the GEA attracts significant amounts of the distributed generation. (3) The standard should include a requirement for mandatory testing/re-calibration period for both ULFS relays and generator under and over frequency relays. The Generator Operator/Owner needs an obligation to provide this information. (4) Governor action can help mitigate adverse effects of disturbances that affect frequency. Should this standard include some requirements for governor response?

Group

IRC Standards Review Comittee

IESO

No

By definition, a continent wide standard intends to direct all regions into a consistent requirement and requires regions with varying practices to agree to a single standard. We support the approach taken in PRC-006-01 that specifies only the upper and lower bounds of UFLS protection requirements. We believe this is a reasonable approach to establish continent-wide requirements and allow regional expertise to design their regional UFLS programs. We agree with the proposal to preserve the intent of utilizing specific expertise within the regions to develop UFLS programs, but do not agree with the applicability and the way the standard is written to hold the "Group of Planning Coordinators" responsible for the requirements. Please see our comments under Q1b

No

We do not agree with the SDT to remove the Regional Entities from being assigned requirements on the basis that: "… the Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements." There are a number of existing standards, for examples: CIP standards, BAL-002,

EOP-004, EOP-007, FAC-013, FAC-012, to name a few, that hold the Regional Entities (Regional Reliability Organizations, as written) responsible for standard requirements. Unless and until an assessment is conducted to conclude that all such requirements can be replaced with an alternative responsible entity(ies), we do not see a problem with the Regional Entities being held responsible for complying with standards. The way the requirements are assigned in this draft standard ("each group of Planning Coordinators shall") leaves room for confusion to the industry and debates in the compliance audit process. Unless the "Group of PCs" is registered as an entity, we are unable to see how the pertinent requirements can be legally enforced. An alternative is to assign these requirements to the Regional Entities, OR, develop a requirement for each PC to have an agreement with its Regional Entity to engage in the design of a UFLS program and coordinate settings with other PCs' programs to achieve consistent application across the region. This way, the requirements can be written to hold "Each Planning Coordinator" rather than "Each group of Planning Coordinators". If this approach is adopted, R1 and R2 could be combined as follows: R1. Each Planning Coordinator shall have an agreement with its Regional Entity to participate with other Planning Coordinators within the region in coordinating the design of an underfrequency load shedding program for consistent application across the region. With this change, R3 may be combined with R1 or be a separate requirement holding each PC responsible for engaging in the development of the criteria. And R3 to R8 can be revised to "Each Planning Coordinator, in meeting the intent of R1, shall…" The proposed changes provide clarity to the PC's responsibility and removes gray areas in the compliance audit process.
No
NERC standards and requirements should not attempt to further define the functional entities. For those transmission owners that have facilities that meet the NERC definition of Distribution Provider, they should be registered in the compliance registry as such. If the interpretation of the current definition is that it does not include "Transmission Owners with end-use Load connected to their facilities…", we recommend the definition of Distribution Provider be updated. The Functional Model does not preclude assigning this responsibility to the Transmission Owners with end-use Load connected to their facilities where such end-use load is not part of a Distribution Provider's load. Excerpt from Chapter 14 of the Version 4 Functional Model – Technical Document, below, describes this process: [When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedance of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.] Loads that are connected to the transmission facilities and where such loads are not part of the DP's loads can and should be curtailed by the TOP action (to relieve constraints) or by the UFLS relays provided by the TOs (to arrest frequency decline). If the SDT is still undecided on this issue, we suggest the SDT consult the FMWG
Yes
We agree but we think you meant R7, not R8. And assuming that the expected loss of generation (for generators tripping at or above 58.0 Hz) is to be compensated by selecting an additional, equivalent amount of load in the UFLS program, the additional load reduction would also need to be simulated.
Yes
We agree with this requirement but believe there should be more specific language on what schemes should be included in the study. There may also be automatic load restoration schemes that have an impact on stabilizing system frequency but was not installed with that intent. The study should also consider the effects of these automatic restoration schemes. Again, we think you meant R7, not R9. We agree. Any pre-determined actions such as tripping of additional load for generator tripping at or above 58.0 Hz as discussed in Q3, above, and automatic restoration of load, etc. should be modeled and assessed via simulations to evaluate frequency performance of potential islands.
Yes
We do not have a concern with this requirement if the 0.2 Hz above 58.0 Hz is intended as a margin/buffer to ensure generators do not trip pre-maturely.
No
We do not see the need to specify these criteria in the standard. Applicable requirements should be assigned to all generators that meet the compliance registry criteria.
None
R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria. The fourth bullet in R5 is unnecessary since (all assets) – (assets in Island 1) – (assets in island 2) - ….. = (remaining assets not in any other island) Alternatively, the SDT may want to consider a requirement to perform one or more ad hoc "stress tests" that can be used to define islanding conditions. If PC passes the stress test, than there is no obligation to define an "island" within the PC; if the PC fails the stress test, than the PC must use the results as a partial (or complete) basis for defining one or more PC islands
Individual
Alice Murdock
Xcel Energy
Yes
No
We feel 4.3 should be removed. Additionally, we feel that the informal formation of a group for the Planning Coordinators in non-RTO areas is problematic. We feel a new registered entity should be created, perhaps called the Planning Coordinator Group. This group would develop a governing document that spells out roles, responsibilities,

etc. like a Reserve Sharing Group does. We feel this approach would best resolve issues surrounding coordination, compliance audits, entity identification in situations of potential non-compliance, penalty assessment, etc. The individual Planning Coordinators would still be required to join a group in their region, per R1. But, the remainder of the requirements should only refer to the Planning Coordinator Group. If the Regional Entity is not going to play a role in coordinating the Planning Coordinators, then we are unsure how an entity would join a group or attach itself to a group. We feel that in non-RTO areas, the Regional Entity should at least serve as a single point of contact for all Planning Coordinators in that region.
No
We feel 4.3 should be removed.
Yes
The dynamic simulation would need to include any small generators (<20MVA or <75MVA aggregate) that are not required to register, but together, could have a material impact on the BES. Additionally, it would need to be clear who is responsible for ensuring those material impacts are included in models/simulations.
Yes
(We assume you meant R7, not R9.)
Yes
We support the philosophy that load shedding should occur prior to generation tripping. We feel it is important to keep these two projects coordinated.
No
No. Criteria in 6.4.1 and 6.4.2 looks like it is only measuring generators that are required to be registered. Yet, with increasing penetration of small generators (<20MVA, <75 MVA aggregate), we feel the scope is not large enough to consider a material impact on the BES by an aggregate of these small generators. (Same concern carries into R7)
We feel R6.4 is not complete without consideration of other BES components, such as transformers and reactive devices. To ensure excessive voltage does not cause further damage or perpetuate the situation, we feel these additional components should be considered. We feel that the use of the word “region” in R1 is unclear. We assume the SDT intended to refer to the 8 NERC regions? (MRO, SPP, WECC, RFC, SERC, etc.) If so, please make that clear in the requirement.

Consideration of Comments on the Second Draft of the PRC-006-1 - Underfrequency Load Shedding Program Requirements — Project 2007-01

The Underfrequency Load Shedding Standard Drafting Team (UFLS SDT) thanks all commenters who submitted comments on PRC-006-1 – Automatic Underfrequency Load Shedding. The standard was posted for a 30-day public comment period from April 20- May 21, 2009. Stakeholders were asked to provide feedback on the document through a special electronic standard comment form. There were 45 sets of comments, including comments from more than 120 different people from over 80 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Summary of Changes:

The applicability section of the second draft of the standard included "Distribution Providers" and "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load." This second draft language reflected the SDT's intent to establish the applicable entities in the UFLS standard to be those entities that supply UFLS capability. However, as a result of comments submitted in the second posting and further discussions within the SDT, the SDT now believes that the identification of the applicable entities was not an entirely accurate reflection of the participating registered entities. Therefore, the applicability section was modified. The SDT is now proposing that "UFLS entities" within the standard shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include Transmission Owners and/or Distribution Providers. The concept to define a group of entities within the body of the standard in the Applicability section currently exists in the CIP-002-1. In addition, the SDT included Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators in the applicability section of the standard. Transmission Owners would be subject to the standard if they have been identified by the group of Planning Coordinators as having the obligation to switch certain Elements as part of the UFLS program.

In the second posting, many of the requirements were assigned to groups of Planning Coordinators. These groups were to consist of all the Planning Coordinators within each of the Regional Entity footprints. The SDT has now revised these assignments to replace the groups with individual Planning Coordinators due to difficulties involved in assigning responsibilities to groups that do not currently exist. In the revised standard, each Regional Entity footprint must be designated as an island for UFLS program design assessment purposes. While the individual Planning Coordinator UFLS program designs maybe different, this amendment will preserve a measure of coordination at the regional level.

The SDT has revised the under and overfrequency performance characteristics to refer to under and overfrequency curves (as Attachments 1 and 2) rather than discrete points as in former drafts. The SDT believes that curves provide more uniform coordination with generator under and overfrequency tripping requirements being proposed in PRC-024-1. In addition, the team extended the underfrequency performance characteristic curve to 60 seconds from the previous 30 second duration. The team agreed to extend the underfrequency performance characteristic to permit the MRO Region to avoid having to specify a variance to cover instances where there may be slower recovery of frequency. The SDT believes that recovery of frequency within 60 seconds, though somewhat less stringent than requiring recovery within 30 seconds, remains acceptable for reliability and for coordination with generator underfrequency tripping. The SDT has similarly substituted the discrete points used in former drafts, for identifying which generator trip settings need to be included in the assessments of UFLS program design, with curves. These curves are shown on the same graphs as the performance characteristic curves (in Attachments 1 and 2) and are the same curves as are being proposed in PRC-024-1 for generator under and overfrequency tripping, thus ensuring explicit coordination between UFLS and generator tripping.

The SDT has modified the approach for ensuring coordination between regions and for selecting islands that overlap adjacent regions within an interconnection. The SDT has deleted the requirement that involved the development of procedures for coordination between groups of Planning Coordinators in neighboring regions in selecting interregional islands (version 2 of draft standard Requirement R4). In version 3 of the draft standard, any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating this selection with neighboring regions. The SDT has added a requirement for the Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by anyone Planning Coordinator that encompass more than one Planning Coordinator footprint. This revised approach to interregional coordination is contained in Requirements R5 and R13.

Some commenters noted that switching of certain transmission facilities is sometimes necessary to be carried out as part of a UFLS program design. The SDT agreed and has added Requirement R10 which requires Transmission Owners to provide automatic switching of Elements in accordance with the UFLS program design should a Planning Coordinator determine that such switching is a necessary part of the UFLS program design.

The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program."(Requirement R11). Requirement R12 requires the Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, to conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. Lastly, Requirement R13 requires the Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, to reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment completion. In the former drafts, event analysis was left to be covered by the NERC Rules of Procedure. However, the drafting team believes that including a requirement in this standard for UFLS event analysis is a more appropriate mapping of PRC-009-0 Requirement R1 which will be replaced by this standard, PRC-006-1.

Earlier in 2009, NPCC identified the need for a variance to the standard for the Québec Interconnection within NPCC. Due to the physical characteristics of the Québec system the UFLS program in Québec arrests frequency at a lower threshold and permits higher frequency overshoot than allowed in the proposed standard. The installed generation in the Québec Interconnection is 98 percent hydraulic generation, allowing wider tolerances on frequency performance without jeopardizing reliability. The variance also establishes a different capacity threshold for the generating units for which underfrequency and overfrequency trip settings must be modeled to address concerns that by 2020, 10 percent of the installed capacity in Québec may be located at plants less than 75 MVA. The Standards Committee appointed a member from the Québec Interconnection to the drafting team to develop the variance for Québec. Working closely with this representative, the team developed the variance to Requirement R3 Parts 3.1 and 3.2 and Requirement R4 Parts 4.1 through 4.6. The variance to these requirements reference separate under frequency and overfrequency curves included as attachments 1A and 2A to the standard.

In reviewing the responses to comments on the second posting, several commenters noted that certain requirements in the exiting EOP-003-1 standard conflict or are redundant with the requirements being proposed by this SDT. The team agreed with these commenters and felt that if left unaddressed, the redundancies and conflicts could result in compliance issues in the future. As a result, the team submitted a request to supplement the existing SAR for Project 2007-01 to include a revision to EOP-003-1 in order to exclude those requirements related to automatic underfrequency load shedding since PRC-006-1 will contain these. The Standards Committee approved this action and the team moved forward with revising the existing EOP-003-1 requirements. The team is presenting these modifications to the EOP-003-1

requirements in this third posting of the standard and would like industry feedback on the revisions noting that the changes were conducted with the limited purpose of removing automatic underfrequency load shedding from the scope of EOP-003. Two other drafting teams are already in place to review the other aspects of EOP-003 as part of Project 2009-02 – Real-time Tools and Project 2009-03 – Emergency Operations.

The team debated whether or not, in Requirement R4, Parts 4.1 through 4.6, to include under and over frequency trip settings only for generators connected to the BES above the stated size thresholds, or all generators above the stated size thresholds whether BES connected or not, though practically limited to 60 kV and above connections. The question here is not applicable to Generator Owners, but simply whether generator under frequency trip settings above the (proposed) under frequency curve in PRC-024-1, and generators with over frequency trip settings below the (proposed) PRC-024-1 over frequency curve, should be represented in the UFLS design assessments.

Limiting Requirement R4, Parts 4.1 through 4.6, to BES connected generation would be consistent with the NERC Statement of Compliance Registry Criteria. It was also noted that some generators on lower voltage systems above the size thresholds may not be modeled, or that they are sometimes lumped with load in planning base cases such that there could be inconsistent enforcement of this requirement if it were extended to include generators not connected to the BES. On the other hand, a distinction between BES and non-BES tripped generation is immaterial to system frequency; the amount of generation that could potentially be tripped during a frequency event is the only relevant factor. Limiting Requirement R4 to BES connected generation would also be inconsistent with PRC-024-1 Applicability Section 4.2 in its current draft (draft #2 not yet posted for comment) which includes generation down to 60 kV.

The SDT limited Requirement R4 to generators connected to the BES only. Note that this same issue also applies to Requirement R3, Part 3.3, in the monitoring of V/Hz at generators.

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Brian Bartos	TRE UFLS Standard Drafting Team	X	X			X		X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randy Jones	Calpine	ERCOT	5
2.	Raborn Reader	EPCO	ERCOT	NA
3.	Eddy Reece	Rayburn Country Electric Coop.	ERCOT	NA
4.	Barry Kremling	Guadalupe Valley Electric Coop.	ERCOT	NA
5.	Sergio Garza	Lower Colorado River Authority	ERCOT	5
6.	Steve Myers	ERCOT ISO	ERCOT	2
7.	Ken McIntyre	ERCOT ISO	ERCOT	2
8.	Dennis Kunkel	AEP	ERCOT	1
9.	Matt Pawlowski	NextEra	ERCOT	5

2.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	David O'Connor	Potomac Electric Power Co	RFC	1
2.	Dave Thorne	Potomac Electric Power Co	RFC	1
3.	Vic Davis	Delmarva Power & Light	RFC	1

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
4. John Keller		Atlantic City Electric	RFC						1			
5. Walt Blackwell		Potomac Electric Power Co	RFC						1			
6. Alvin Depew		Potomac Electric Power Co	RFC						1			
3. Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Kelly Johnson	Transmission Customer Service Engineering	WECC	1
2. Greg Vasallo	Transmission Customer Service Engineering	WECC	1
3. Larry Furumasu	Transmission Planning	WECC	1

4. Group	Guy Zito	Northeast Power Coordinating Council										X

Additional Member	Additional Organization	Region	Segment Selection
1. Ralph Rufrano	New York Power Authority	NPCC	5
2. Alan Adamson	New York State Reliability Council	NPCC	10
3. Greg Campoli	New York Independent System Operator	NPCC	2
4. Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5. Kurtis Chong	Independent Electricity System Operator	NPCC	2
6. Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7. Manuel Couto	National Grid	NPCC	1
8. Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9. Brian Evans-Mongeon	Utility Services	NPCC	8
10. Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11. Michael Gildea	Constellation Energy	NPCC	6
12. Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
13. Kathleen Goodman	ISO - New England	NPCC	2
14. David Kiguel	Hydro One Networks Inc.	NPCC	1
15. Michael Lombardi	Northeast Utilities	NPCC	1
16. Randy MacDonald	New Brunswick System Operator	NPCC	2
17. Bruce Metruck	New York PowerAuthority	NPCC	6

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
18. Robert Pellegrini		The United Illuminating Company	NPCC						1			
19. Michael Schiavone		National Grid	NPCC						1			
20. Michael Sonnelitter		FPL Energy/NextEra Energy	NPCC						5			
21. Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC						3			
22. Lee Pedowicz		Northeast Power Coordinating Council	NPCC						10			
23. Gerry Dunbar		Northeast Power Coordinating Council	NPCC						10			
5. Group	Jim Busbin	Southern Company	X		X		X					
Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1. J. T. Wood		Southern Company Services, Inc.	SERC						1			
2. Hugh Francis		Southern Company Services, Inc.	SERC						1			
3. Bill Shultz		Southern Company Services, Inc.	SERC						5			
4. Phil Winston		Georgia Power Company	SERC						3			
5. Jonathan Glidewell		Southern Company Services, Inc.	SERC						1			
6. Marc Butts		Southern Company Services, Inc.	SERC						1			
6. Group	Ken McIntyre	ERCOT ISO		X								
Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1. Steve Myers		ERCOT ISO	ERCOT						2			
2. John Schmall		ERCOT ISO	ERCOT									
7. Group	Jalal Babik	Electric Market Policy	X		X		X	X				
Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1. Louis Slade			SERC						6			
2. Mike Garton			NPCC						5			
8. Group	Jason L. Marshall	Midwest ISO Stakeholders Standards Collaborators		X								
Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1. Lee Kittleson		Otter Tail Power	MRO						1			
2. Michael Ayotte		ITC Holdings	RFC						1			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Bob Jones	SERC UFLS Standards Drafting Team	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Foster	Ameren Services Co.	SERC	1
2.	John O'Connor	Progress Energy Carolinas	SERC	1
3.	Pat Huntley	SERC Reliability Corp.	SERC	10
4.	Jonathan Glidewell	Southern Co. Services	SERC	1
5.	Tom Cain	TVA	SERC	1

10.	Group	Peter A. Heidrich	FRCC Standards & Operations Departments										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Linda Campbell	Florida Reliability Coordinating Council	FRCC	10
2.	Eric Senkowicz	Florida Reliability Coordinating Council	FRCC	10

11.	Group	Frank Gaffney	Florida Municipal Power Agency and Select Members	X		X	X	X				X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rich Kinas	Orlando Utilities Commission	FRCC	1, 3, 5
2.	Jim Howard	Lakeland Electric	FRCC	1, 3, 5
3.	Greg Woessner	Kissimmee Utilities Authority	FRCC	1, 3, 5
4.	Cairo Venegas	Fort Pierce Utilities	FRCC	1, 3, 5

12.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carol Gerou	MRO	MRO	10
2.	Neal Balu	WPS	MRO	3, 4, 5, 6
3.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
4.	Ken Goldsmith	ALTW	MRO	4
5.	Jim Haigh	WAPA	MRO	1, 6
6.	Terry Harbour	MEC	MRO	1, 3, 5, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Joseph Knight		GRE	MRO						1, 3, 5, 6			
8.	Scott Nickels		RPU	MRO						3, 4, 5, 6			
9.	Dave Rudolph		BEPC	MRO						3, 4, 5, 6			
10.	Eric Ruskamp		LES	MRO						1, 3, 5, 6			
11.	Terry Bilke		MISO	MRO						2			
13.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				
	Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1.	Tim Hinken		Kansas City Power & Light	SPP						1, 3, 5, 6			
2.	Nick McCarty		Kansas City Power & Light	SPP						1, 3, 5, 6			
3.	Jerry Hatfield		Kansas City Power & Light	SPP						1, 3, 5, 6			
14.	Group	Ben Li	IRC Standards Review Committee		X								
	Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1.	James Castle		NYISO							2			
2.	Anita Lee		AESO							2			
3.	Charles Yeung		SPP							2			
4.	Bill Phillips		MISO							2			
5.	Matt Goldberg		ISO-NE							2			
6.	Steve Myers		ERCOT							2			
7.	Patrick Brown		PJM							2			
15.	Individual	Russell A. Noble	Cowlitz County PUD			X							
16.	Individual	Edward C. Stein	Edward C. Stein - Self								X		
17.	Individual	Harvie Beavers	Colmac Clarion					X					
18.	Individual	Elvin Epting	City of Bedford			X							
19.	Individual	Ray Phillips	Alabama Municipal Electric Authority				X						

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Karl Bryan	US Army Corps of Engineers					X					
21.	Individual	Tom Nappi	NIPSCO	X		X		X					
22.	Individual	Kenneth D. Brown b/h Joseph Lalier, Design Engineer Electric Delivery Planning	Public Service Electric and Gas Company	X		X							
23.	Individual	Steve Alexanderson	Central Lincoln			X							
24.	Individual	Shawn Jacobs	SPP System Protection and Control Working Group	X	X	X							X
25.	Individual	Jonathan Appelbaum	Long island power Authority	X									
26.	Individual	Eric Mortenson	Exelon	X		X		X					
27.	Individual	Rao Somayajula	ReliabilityFirst Corporation										X
28.	Individual	Ronnie Frizzell	Arkansas Electric Cooperative Corporation				X						
29.	Individual	Greg Davis	System Protection & Control	X		X							
30.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
31.	Individual	Anthony Jablonski	Reliability First										X
32.	Individual	Bob Thomas, Kevin Wagner, Troy Fodor, Scott Robison	Illinois Municipal Electric Agency				X						
33.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
34.	Individual	Jim Sorrels	AEP	X		X		X	X				
35.	Individual	Vladimir Stanisic	Ontario Power Generation					X	X				
36.	Individual	Joe Springhetti	We Energies			X	X	X					
37.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
38.	Individual	Mike Sonnelitter	NextEra Energy Resources, LLC					X					
39.	Individual	Jason Shaver	American Transmission Company	X									
40.	Individual	Rick Terrill	Luminant Power					X					
41.	Individual	Kirit Shah	Ameren	X		X		X	X				
42.	Individual	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
43.	Individual	Armin Klusman	CenterPoint Energy	X									
44.	Individual	Dan Rochester	Independent Electricity System Operator		X								
45.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				

1. **The UFLS programs typically have been developed within each Region by representatives from the vertically integrated utilities, Control Areas, power pools, etc. in that Region. The SDT initially proposed that all UFLS requirements be contained within regional UFLS standards to utilize specific expertise within the regions and recognize that UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics, even across interconnected regions. However, based on the rationale contained in the background, the SDT has developed a continent wide standard consistent with the historical practice that promotes the utilization of previous experience and expertise. As proposed, the continent-wide standard requires that all Planning Coordinators within a Region work together as a group to develop the UFLS program for that Region that conforms to the performance characteristics.**

    a. Do you agree that creating a continent wide standard preserves the intent of utilizing specific expertise within the regions to develop UFLS programs that meet common performance characteristics?

Summary Consideration:

- Most commenters agreed that creating a continent wide standard preserves the intent of utilizing specific expertise within the regions to develop UFLS programs that meet common performance characteristics.
- Commenters suggested that regions might want to develop more detailed or stringent requirements. If a Region wants to develop more stringent requirements the Region may elect to develop a regional standard. The creation of a continent wide standard does not prohibit the creation of regional standards. Several commenters also indicated the need for a Variance. The SDT is proposing a Variance for Hydro-Quebec in the third posting of the standard. Other requests for variances or regional standards should follow the procedure outlined in the NERC Rules of Procedure Appendix 3A – Variances to NERC Reliability Standards and Section 312 - Regional Reliability Standards.
- Some comments indicated concern with the term “consistent” in Requirement R2 of the standard. The SDT developed the performance characteristics so that a “program” could be tailored to the needs of each region; however; at the same time not interfering with adjacent regions. The SDT did not intend that a “program” could have only one set of requirements, such as one set of drop frequencies or one specific percent load drop, for an entire region. A “program” could be made up of different sections or sub regional systems identified as islands with different or the same requirements where consistent application of the applicable program requirements are applied in each island. The SDT merged Requirement R2 into Requirement R6 (now Requirement R3 in the in the third version of the standard) and removed the term “consistent” in the requirement.

Organization	Yes or No	Question 1a Comments:
IRC Standards Review Comittee	No	By definition, a continent wide standard intends to direct all regions into a consistent requirement and requires regions with varying practices to agree to a single standard. We support the approach taken in PRC-006-01 that specifies only the upper and lower bounds of UFLS protection requirements. We believe this is a reasonable approach to establish continent-wide requirements and allow regional expertise to design their regional UFLS programs.We agree with the proposal to preserve the intent of utilizing specific expertise within the regions to develop UFLS programs, but do not agree with the applicability and the way the standard is written to hold the Group of Planning Coordinators responsible for the requirements. Please see our comments under Q1b
Response: Thank you for your support to the continent-wide approach. See the response provided for the comment under Q1b.		
Ameren	No	It seems that regional standards with continent-wide performance characteristics would be the best mechanism to achieve this purpose. The only reason to have a continent wide standard to is to subscribe to the NERC process. There seems to be more focus on the process than the ultimate goal.
Response: The SDT has focused on both the ultimate goal and the process to achieve the goal. We believe the ultimate goal is to have regionally developed UFLS programs that are coordinated across and between regions. As drafted, the proposed standard does not preclude the development of regional standards. The standard directs responsibility to the Planning Coordinators but allows them to develop/establish the UFLS program requirements in any manner they deem appropriate as long as they conform to the performance characteristics.		
Independent Electricity System Operator	No	Further, we propose the scope of the standard be revised to clearly indicate that it focuses on the global events, as follows:To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following widespread underfrequency events.
Response: The SDT does not agree with the inclusion of word "widespread" because of the numerous difficulties in defining "widespread" and the lack of completeness of the intent. The draft standard requires consideration of appropriate potential islands. Such islands may be widespread in some people's minds and not so in others. Widespread, if viewed from a square mile perspective, could include large rural areas with little "critical" load. "Critical" urban load in relatively small concentrated geographic footprints may not necessarily fit within a widespread definition. The drafted purpose allows all these conditions to be included as appropriate with the programs to cover the relevant impacts to the bulk electric system.		
NIPSCO	No	It really depends on how this is accomplished.
Response: The SDT encourages the commenter to provide more specifics in the next posting for SDT consideration.		

Organization	Yes or No	Question 1a Comments:
Duke Energy	No	R2 requires consistent application across the region. As long as R6 is met, there should be no requirement for all systems within the region to be consistent. This will create unnecessary work to redesign systems that could meet R6 just because they are not consistent with other systems in the region. Recommend deleting the words consistent application across from R2. This is similar to not requiring the regions to be consistent as long as R6 is met.
Response: The SDT merged Requirement R2 into Requirement R6 (now Requirement R3 in the in the third version of the standard) and removed the term "consistent" in the requirement.		
We Energies	No	We agree that a continent wide standard should be developed. However, we disagree with the approach taken with this draft of the standard. See our question 8 comments for more detail.
Response: Thank you for the support of a continent-wide standard. See the response to your comments on Question 8.		
TRE UFLS Standard Drafting Team	Yes	The Texas Regional Entity Underfrequency Load Shedding Standard Drafting Team (TRE UFLS SDT) is pleased to provide these comments. These comments reflect the consensus of this specific regional standard drafting team and do not reflect the position of the Texas Regional Entity or ERCOT. The TRE UFLS SDT agrees that the basic common characteristics associated with the proposed UFLS standard provides for an appropriate level of required coordination within and, where applicable, between regions.
Response: Thank you for your comment.		
Pepco Holdings, Inc - Affiliates	Yes	The PHI Affiliates agree that the Planning Coordinators have their own expertise and access to the expertise of the TOs and DPs in their area.
Response: Thank you for your support to the continent-wide approach.		
Bonneville Power Administration	Yes	The continent-wide standard is a MINIMUM. Regions may still apply a higher standard.
Response: If a Region wants to develop more stringent requirements the Region may elect to develop a regional standard. The creation of a continent wide standard does not prohibit the creation of regional standards. Requests for variances or regional standards should follow the procedure outlined in the NERC Rules of Procedure Appendix 3A – Variances to NERC Reliability Standards and Section 312 - Regional Reliability Standards.		
SERC UFLS Standards	Yes	We agree that creating a continent wide standard will preserve the intent of utilizing specific expertise within the

Organization	Yes or No	Question 1a Comments:
Drafting Team		region to develop UFLS schemes. First of all, this approach will provide uniformity among the regions for developing UFLS schemes, as all the regions will follow a consistent performance characteristics specified in the standard. At the same time, the regions will have the flexibility to develop their own requirements to meet their specific needs.
Response: Thank you for your comment.		
Southern Company	Yes	Southern Company agrees with the comments submitted by the SERC Region for all questions in this comment form. Submitted SERC responses are essentially replicated in the responses we submit for Southern Company for questions 1-8.**********We agree that creating a continent wide standard will preserve the intent of utilizing specific expertise within the region to develop UFLS schemes. First of all, this approach will provide uniformity among the regions for developing UFLS schemes, as all the regions will follow consistent performance characteristics specified in the standard. At the same time, the regions will have the flexibility to develop their own requirements to meet their specific needs.
Response: Thank you for your comment.		
FRCC Standards & Operations Departments	Yes	We agree with the concept of the development of a Regional UFLS program that conforms to the common performance characteristics contained in the draft standard; however it is not clear what constitutes a 'region'. The SDT has repeatedly used the capitalized version ('Region') of the word in all of the associated documents (i.e. background, comment form) and reverted back to lower case version (region) in the standard. We believe that 'region' should be defined in the standard and incorporated into the NERC Glossary of Terms. This will ensure that the appropriate scope is applied in the development of Regional UFLS programs.
Response: The SDT intended "region" to relate to the traditional sense of a RRO with defined boundaries and that is in the NERC Glossary, although somewhat out of date. The SDT did inadvertently capitalize the word "region" in the associated documents but did use it appropriately in the standard. The SDT has replaced "region" with "Regional Entity footprint."		
US Army Corps of Engineers	Yes	The continent wide standard establishes the performance characteristics that must be met and requiring the PCs within a Region to develop the specifics allows the implementation of the Rel Stndrd to also include local variances and has the added benefit of maintaining planning expertise.
Response: Thank you for your support to the continent-wide approach.		
Public Service Electric and Gas Company	Yes	The creation of a continent wide standard is acceptable as long as the responsibility for developing a UFLS program remains with the Planning Coordinators/Authorities in the Regions.

Organization	Yes or No	Question 1a Comments:
Response: Thank you for your support to the continent-wide approach.		
System Protection & Control	Yes	A continent wide standard will create desired system performance criteria, while allowing flexibility within the regions.
Response: Thank you for your support to the continent-wide approach.		
AEP	Yes	As each Reliability Coordinator has it's own UFLS requirements, the UFLS programs between the Reliability Coordinator's need to work together.
Response: Thank you for your comment. Reliability Coordinators are not included in this standard because this standard addresses only multi-step automatic relay tripping and load shedding, not manual load shedding. The draft standard includes requirements to ensure coordination within a region by designating each Regional Entity footprint as a required island for which the performance characteristics must be satisfied, and by requiring Planning Coordinator concurrence on UFLS design assessment results on those islands.		
PacifiCorp	Yes	PacifiCorp believes that the standard language is general enough to allow for regional differences. It is appropriate that the standard addresses what the parameters are, not how the parameters are to be implemented.
Response: Thank you for your support to the continent-wide approach.		
Northeast Power Coordinating Council	Yes	
ERCOT ISO	Yes	
Electric Market Policy	Yes	
Midwest ISO Stakeholders Standards Collaborators	Yes	
Florida Municipal Power Agency and Select Members	Yes	

Organization	Yes or No	Question 1a Comments:
MRO NERC Standards Review Subcommittee	Yes	
Kansas City Power & Light	Yes	
Cowlitz County PUD	Yes	
Edward C. Stein	Yes	
Colmac Clarion	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
Central Lincoln	Yes	
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
Exelon	Yes	
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	Yes	

Organization	Yes or No	Question 1a Comments:
ReliabilityFirst	Yes	
Illinois Municipal Electric Agency	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Ontario Power Generation	Yes	
NextEra Energy Resources, LLC	Yes	
American Transmission Company	Yes	
Luminant Power	Yes	
FirstEnergy Corp	Yes	
Xcel Energy	Yes	

b. Do you agree that the SDT has assigned responsibility to the appropriate entity?

Summary Consideration:

1. Some commenters expressed concern over the "group" concept for Planning Coordinators and how it would be implemented. The SDT has removed the group concept from the standard. The applicability has been changed to individual Planning Coordinators. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning Coordinators join a group that does not presently exist.
2. While some commenters agreed with the concept of the coordinated effort to design an underfrequency load shedding program, they expressed a need to establish an entity with the overall responsibility of coordinating the efforts of the Planning Coordinators. These commenters recommended that the Regional Entity be responsible for overseeing the development of the Regional UFLS program while requiring the Planning Coordinators to participate in the process. The SDT notes that Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard.
3. Some commenters thought that Generator Owner should be included as an applicable entity. This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.
4. Some commenters thought that the Transmission Planner is the more appropriate applicable entity. The SDT believes the Planning Coordinator is the most appropriate applicable entity because design of a UFLS program should consider the widest possible geographic area. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role, the SDT anticipates that the Transmission Planners' expertise will be utilized.
5. Some commenters indicated that Reliability Coordinators should be included in the standard. Reliability Coordinators are not included in this standard because this standard addresses only multi-step automatic relay tripping and load shedding that must be planned and implemented in advance. The SDT believes that Planning Coordinators are the appropriate entities for this function. Manual load shedding is not covered by this standard.
6. Some commenters stated that the Transmission Owner should be removed as an applicable entity because any Transmission Owner with load must be registered as a Distribution Provider. In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. (Also covered under Question 1b.)

Organization	Yes or No	Question 1b Comments:
Northeast Power Coordinating Council	No	We agree that the Planning Coordinator is the correct Functional Model entity based on having a wide-area view and the planning expertise to perform UFLS assessments. However, it is not clear to us whether applicability can be assigned to a group of Planning Coordinators as opposed to individual Planning Coordinators.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
Midwest ISO Stakeholders Standards Collaborators	No	We can understand the assignment of certain responsibilities to a Planning Coordinator. However, attempting to force Planning Coordinators to develop groups and then holding the entire group accountable for one another's compliance is unworkable.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
SERC UFLS Standards Drafting Team	No	No, because Planning Coordinator(PC) role is implemented differently across the regions. The Transmission Planner(TP) is the most appropriate entity to design the UFLS scheme since the TP has the detailed system knowledge and is generally better positioned to develop the scheme. Also, the Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.
Response: The SDT believes the Planning Coordinator is the appropriate applicable entity because design of a UFLS program should consider the widest possible geographic area. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role, the SDT believes that the Transmission Planners' expertise will be utilized. **The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.**		
Southern Company	No	No, because the Planning Coordinator (PC) role is implemented differently across the regions. The Transmission Planner (TP) is the most appropriate entity to design the UFLS scheme since the TP has the detailed system knowledge and is generally better positioned to develop the scheme. Also, the Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the

Organization	Yes or No	Question 1b Comments:
		Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.
Response: The SDT believes the Planning Coordinator is the appropriate applicable entity because design of a UFLS program should consider the widest possible geographic area. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role the SDT anticipates that the Transmission Planners' expertise will be utilized. **The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.**		
FRCC Standards & Operations Departments	No	Although we agree with the concept of the coordinated effort to design an underfrequency load shedding program, we believe that there is a need to establish an entity with the overall responsibility of coordinating the efforts of the Planning Coordinators. We recommend that the Regional Entity be responsible for overseeing the development of the Regional UFLS program while requiring the Planning Coordinators to participate in the process. Although the provided background material dismisses the idea of expanding the applicability to include the Regional Entity, the precedent has been established by assigning applicability to the Regional Entity in the CIP standards.
Response: Unfortunately, though the SDT agrees with the commenter's point on assigning applicability to Regional Entities, Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard.		
Florida Municipal Power Agency and Select Members	No	While we agree that the responsibility resides with a regional planning coordinator type of Entity, a group of Planning Coordinators is a somewhat nebulous term and calls into question the enforceability of the standard, and therefore calls into question whether FERC will approve it or not. If the group of Planning Coordinators is noncompliant, who is noncompliant? Who negotiates settlement? Who would pay a potential fine? If one of the Entities does not provide data for the database required in R8, are all of the PCs noncompliant? As with nearly all things, in order to get something done, leadership is necessary, so, although this is certainly a team effort, one Entity ought to be designated to offer that leadership. Why not keep it the Regional Entity? Alternatively, is there sufficient justification to create a new function called the Regional Planning Coordinator? Or to change the definitions of Planning Coordinator, Transmission Planner and Resource Planner to essentially cause Transmission Planners and Resource Planners to focus on more local issues whereas the Planning Coordinator by definition becomes regional (and hence eliminates the need for the term a group of Planning Coordinators?)
Response: Thank you for your comment. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning Coordinators join a group that does not presently exist. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators. Unfortunately, though the SDT agrees with the commenter's point on assigning		

Organization	Yes or No	Question 1b Comments:
applicability to Regional Entities, Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard.		
MRO NERC Standards Review Subcommittee	No	We agree with the assignment of selected responsibilities to the Planning Coordinator (PC) and suggest that the NERC Compliance Registry Criteria be revised to add the Planning Coordinator function and the Regional Entities be directed to register applicable entities to this function. Responsibility for several requirements are assigned to a "group" of Planning Coordinators. However, these groups do not presently exist and are not registered or legal entities. Perhaps a Planning Coordinator Group (PCG) should be added to the Applicability section and the NERC Compliance Registry Criteria be revised to add the PCG function, similar to the Reserve Sharing Group (RSG) function. Then, Regional Entities might be directed to register applicable entities to this function. Establishing PCGs would help PCs clarify how the group's responsibilities for compliance and liabilities would be assigned to each of its members.If a registered PCG function is not established, then drafting team should revise R1 to require all Planning Coordinators in a region to form a joint agreement to cover fulfillment of the subsequent UFLS requirements. See details in response to question 8. Transmission Owners function should be removed because it is unnecessary and redundant with the Distribution Provider function. Per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner that provides and operates the ?wires? to end-use Load served at transmission voltages must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. However, the TO function should be retained if SDT adopts the suggestion of adding R11 and R12 reguarding reactive power devices (in Q8). Generator Owners should be assigned responsibility for coordinating any generator off nominal frequency protection with any applicable UFLS relaying and for providing generator off nominal frequency protection information to the Planning Coordinator. So, the Generator Owner function should be added to the Applicability section. The SDT should coordinate with PRC-024 so that requirements do not overlap.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning Coordinators join a group that does not presently exist. **In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.** **Regarding the comment on reactive power devices referred to in Question 8 the team directs the commenter to the SDT response under Question 8.** **This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-**		

Organization	Yes or No	Question 1b Comments:
024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.		
Kansas City Power & Light	No	It is unnecessary to designate a Transmission Provider with end-use load. That is a Distribution Provider. Generator Owners should be added since generator data will be required to be provided for modeling purposes.
Response: The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. **This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.**		
IRC Standards Review Comittee	No	We do not agree with the SDT to remove the Regional Entities from being assigned requirements on the basis that: ?? the Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements.? There are a number of existing standards, for examples: CIP standards, BAL-002, EOP-004, EOP-007, FAC-013, FAC-012, to name a few, that hold the Regional Entities (Regional Reliability Organizations, as written) responsible for standard requirements. Unless and until an assessment is conducted to conclude that all such requirements can be replaced with an alternative responsible entity(ies), we do not see a problem with the Regional Entities being held responsible for complying with standards.The way the requirements are assigned in this draft standard (each group of Planning Coordinators shall) leaves room for confusion to the industry and debates in the compliance audit process. Unless the Group of PCs is registered as an entity, we are unable to see how the pertinent requirements can be legally enforced. An alternative is to assign these requirements to the Regional Entities, OR, develop a requirement for each PC to have an agreement with its Regional Entity to engage in the design of a UFLS program and coordinate settings with other PCs? programs to achieve consistent application across the region. This way, the requirements can be written to hold Each Planning Coordinator rather than Each group of Planning Coordinators. If this approach is adopted, R1 and R2 could be combined as follows:R1. Each Planning Coordinator shall have an agreement with its Regional Entity to participate with other Planning Coordinators within the region in coordinating the design of an underfrequency load shedding program for consistent application across the region.With this change, R3 may be combined with R1 or be a separate requirement holding each PC responsible for engaging in the development of the criteria.And R3 to R8 can be revised to ?Each Planning Coordinator, in meeting the intent of R1, shall?The proposed changes provide clarity to the PC?s responsibility and removes gray areas in the compliance audit process.
Response: The SDT notes that Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning		

Organization	Yes or No	Question 1b Comments:
Coordinators join a group that does not presently exist. Accordingly, the SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
Independent Electricity System Operator	No	We do not agree with the SDT to remove the Regional Entities from being assigned requirements on the basis that: ?? the Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements. There are a number of existing standards, for examples: CIP standards, BAL-002, EOP-004, EOP-007, FAC-013, FAC-012, to name a few, that hold the Regional Entities (Regional Reliability Organizations, as written) responsible for standard requirements. Unless and until an assessment is conducted to conclude that all such requirements can be replaced with an alternative responsible entity(ies), we do not see a problem with the Regional Entities being held responsible for complying with standards.The way the requirements are assigned in this draft standard (each group of Planning Coordinators shall) leaves room for confusion to the industry and debates in the compliance audit process. Unless the Group of PCs is registered as an entity, we are unable to see how the pertinent requirements can be legally enforced. An alternative is to assign these requirements to the Regional Entities, OR, develop a requirement for each PC to have an agreement with its Regional Entity to engage in the design of a UFLS program and coordinate settings with other PCs programs to achieve consistent application across the region. This way, the requirements can be written to hold Each Planning Coordinator rather than Each group of Planning Coordinators. If this approach is adopted, R1 and R2 could be combined as follows:R1. Each Planning Coordinator shall have an agreement with its Regional Entity to participate with other Planning Coordinators within the region in coordinating the design of an underfrequency load shedding program for consistent application across the region.With this change, R3 may be combined with R1 or be a separate requirement holding each PC responsible for engaging in the development of the criteria.And R3 to R8 can be revised to ?Each Planning Coordinator, in meeting the intent of R1, shall??The proposed changes provide clarity to the PC?s responsibility and removes gray areas in the compliance audit process.
Response: The SDT notes that Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning Coordinators join a group that does not presently exist. Accordingly, the SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
Central Lincoln	No	"Transmission Owners with end-use Load connected to their Facilities where suchend use load is not part of a Distribution Providers load"TOs that meet the registry criteria for DP should be registered as such. If they don't meet the criteria, they are not required to have UFLS and this standard is not applicable to the small unregistered distribution system in question. Instead, I propose that TOs be included with no qualification, or a qualification that expresses the following situation: A DP and a TO may jointly decide the most effective location for UFLS may be on the TO's system, where it may be

Organization	Yes or No	Question 1b Comments:
		easier to reach the load shedding target. It would then be the TO that would be required to meet R9 and R10.
Response: The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Exelon	No	GOs should be included as applicable entities because they play an important role in matching load and generation in periods of frequency excursion. That being said, the standard should not require the installation of under frequency relays at generators that would remain on line beyond these minimum requirements.
Response: This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.		
Arkansas Electric Cooperative Corporation	No	I agree with the Planning Coordinator Group concept but this group should be required to solicit the input from other functional entities such as the GO, TO, TOP, DP, and LSE when developing the criteria and plans. These other entities will have valuable insight as to what should and should not be included in the UFlS programs and need to have a voice during the development of these programs. I would suggest adding the following sentence to R2 and R3 "The design(R2)/criteria(R3)shall be developed taking into consideration the input and feedback from the Generator Owners, Transmission Owners, Transmission Operators, Distribution Providers and Load Serving Entities to which the design/critria shall apply." While the Distribution Provider may own the equipment the LSE will play a valuable role in determining which equipment should be used to shed load. The LSE and not necessarily the DP has a better knowledge of the load makeup served by the DP's equipment and thus may be in a better position to identify the best location for UF relays. For example the LSE would know if a circuit has a critical load where the DP may or may not have this knowledge. Since load is what is being dropped, the LSE is the best one to make the determation of which load is to be shed. The LSE may not need be an applicable entity but the UF programs and plans should not be developed without their input.It may be that the standard applicability needs to be expanded to these other entities by adding something to the effect of: GO, TO, TOP, DP, and LSE will participate in the development of the UFLS program and plans by providing input and feedback.
Response: The commenter is referencing issues that must be addressed to determine "how" the program is to be developed and implemented. The standard states measurable requirements for "what" is to be accomplished. Choice of load to be tripped, for example, is an implementation issue not specified in the standard. Responsible entities are allowed to choose the most appropriate manner in which to implement the program design to achieve the reliability objective of arresting frequency decline. The continent-wide standard also does not preclude the use of the regional standard development process that may involve these other entities to produce a regional standard. Note that the SDT has removed the group of Planning		

Organization	Yes or No	Question 1b Comments:
Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
Duke Energy	No	The proposed standard's requirements R1-R8 are applicable to Planning Coordinator, which isn't a registered function in NERC's compliance registry. Without applicability to a registered entity such as the Planning Authority or Transmission Planner, there is no clear responsibility for compliance. Also it is unclear how compliance can reasonably be enforced when responsibility is shared by a group of entities. It is not clear how non-compliance with R6 is addressed given that all PCs in the region are combined by R1. Somehow, each PC must be allowed to demonstrate compliance to the standard independently so compliant PCs are not penalized along with the non-compliant one(s).
Response: NERC has submitted and FERC has accepted a statement that the previously defined term of Planning Authority is the same entity/function as the currently approved Functional Model term Planning Coordinator. Based on the "Comments of the North American Electric Reliability Corporation on the Notice of Proposed Rulemaking for Facilities Design, Connections and Maintenance Reliability Standards", Docket No. RM07-3-000, dated September 19th, 2007, pages 15 and 16, NERC states: "While NERC recognizes there will be a need to modify the compliance registration process to include the planning coordinator, in the future, on an interim basis, any requirement assigned to the planning authority is assumed also to apply to the planning coordinator. Because no approved standards apply to the "planning coordinator at this time, the modification to the NERC Compliance Registry is not a current issue." This document can be found at: http://www.nerc.com/docs/docs/ferc/FinalFAC.pdf. Based on this document, the SDT feels the Planning Coordinator is the correct entity. **In addition, the current NERC Glossary of terms indicates that the Planning Authority and Planning Coordinators are the same.** **The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.**		
ReliabilityFirst	No	The Transmision Owner with end use load connected ... is out of line with the NERC Functional Model knowing that if a Transmision Owner has end use load connected, by definition, the Transmision Owner must register as a Distribution Provider. Therefore, using just the Distribution Provider in the UFLS standard is adequate and complete.
Response: In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Hydro-Québec TransEnergie (HQT)	No	HQT agree that the Planning Coordinator is the correct Functional Model entity based on having a wide-area view and the planning expertise to perform UFLS assessments. However, it is not clear whether applicability can be assigned to a group of Planning Coordinators as opposed to individual Planning Coordinator.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability		

Organization	Yes or No	Question 1b Comments:
has been changed to individual Planning Coordinators.		
AEP	No	Reliability Coordinators have set up specifics standards on the set points for UFLS. The proposed standard misses this circumstance by not including the Reliability Coordinator in the standard. How would this be reconciled?
Response: Reliability Coordinators are not included in this standard because this standard addresses only multi-step automatic relay tripping and load shedding that must be planned and implemented in advance. The SDT believes that Planning Coordinators are the appropriate entities for this function. Manual load shedding is not covered by this standard.		
We Energies	No	See our question 8 comments for more detail.
Response: See response to Question 8 comments.		
American Transmission Company	No	We agree with the assignment of selected responsibilities to the Planning Coordinator (PC) and suggest that NERC revise the Compliance Registry Criteria to add the Planning Coordinator and direct the Regional Entities to register applicable entities to this function. Responsibility for several requirements are assigned to a "group" of Planning Coordinators, but Planning Coordinator Group (PCG) does not appear in the list of applicable entities. We agree with leaving the PCG entity off of the list. However, without a PCG entity in the list, the applicable requirements should be reworded to make each Planing Coordinator individually responsible for their contribution to the group actions. Suggested wording for each applicable requirement is provided in the response to Question 8.If the drafting team decides to apply requirement responsiblities to a PCG, then NERC should revise the Compliance Registry Criteria to add the PSG and direct the Regional Entities to register the applicable entities to this function. Since regional PSGs have not been formed as legal entities in the past, then going this direction would require PC to establish contracts to form these groups in order to clearly define the compliance and sanction liabilities of each PC in the group. Transmission Owners should be removed because it is redundant with Distribution Provider. Per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner that provides and operates the wires to end-use Load served at transmission voltages must register as a Distribution Provider or transferred the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. Therefore, we suggest the removal of Transmission Owner from the Applicability section. Generator Owners (GO) should be included in the Applicable entities section and requirements should be added that assign GOs the responsibility for providing generator off nominal frequency protection information to the Planning Coordinator and for coordinating any generator off nominal frequency protection with any applicable UFLS program.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability		

Organization	Yes or No	Question 1b Comments:
has been changed to individual Planning Coordinators. **In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.** **This standard has not included requirements for Generator Owners since such requirements have been grouped with other generator requirements in PRC-024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.**		
Ameren	No	It seems that the Transmission Planner would be a better choice than the Planning Coordinator for the design of the UFLS programs. The Transmission Planner is more knowledgeable about the how the load and generation interact and how best to model these impacts on the frequency.
Response: The SDT believes the Planning Coordinator is the appropriate applicable entity because design of an UFLS program should consider the widest possible geographic area. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role, the SDT believes that the Transmission Planners' expertise will be utilized.		
FirstEnergy Corp	No	We support the removal of the Transmission Owner with end-use Load connected to their Facilities. The Distribution Provider entity adequately covers all load that is subject to this standard. The Generator Owner should be added to better coordinate their frequency protection with UFLS.
Response: In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. **This standard has not included requirements for Generator Owners since such requirements have been grouped with other generator requirements in PRC-024 which presently is under development. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.**		
Xcel Energy	No	We feel 4.3 should be removed. Additionally, we feel that the informal formation of a group for the Planning Coordinators in non-RTO areas is problematic. We feel a new registered entity should be created, perhaps called the Planning Coordinator Group. This group would develop a governing document that spells out roles, responsibilities, etc. like a Reserve Sharing Group does. We feel this approach would best resolve issues surrounding coordination, compliance audits, entity identification in situations of potential non-compliance, penalty assessment, etc. The individual Planning Coordinators would still be required to join a group in their region, per R1. But, the remainder of the requirements should only refer

Organization	Yes or No	Question 1b Comments:
		to the Planning Coordinator Group.If the Regional Entity is not going to play a role in coordinating the Planning Coordinators, then we are unsure how an entity would join a group or attach itself to a group. We feel that in non-RTO areas, the Regional Entity should at least serve as a single point of contact for all Planning Coordinators in that region.
Response: In some regions, Transmission Owners are the entities that implement UFLS even when they have no load. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. **The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators. The SDT acknowledges the legal and compliance difficulties involved in requiring that Planning Coordinators join a group that does not presently exist.**		
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes specifically that data collection and assessments are most effectively carried out at the regional level. However, it is important to note one issue that will have to be dealt with in the regional standard and/or programs is how to account for the small load-serving systems (e.g., less than 25 MW) that are not NERC-registered.
Response: The SDT agrees with the commenter and offers the following observations. Notes 1 and 4 of the NERC Compliance Registry state in part that "The above are general criteria only. The Regional Entity considering registration of an organization not meeting (e.g., smaller in size than) the criteria may propose registration of that organization if the Regional Entity believes and can reasonably demonstrate that the organization is a bulk power system owner, or operates, or uses bulk power system assets, and is material to the reliability of the bulk power system." And that "If an entity is part of a class of entities excluded based on the criteria above as individually being unlikely to have a material impact on the reliability of the bulk power system, but that in aggregate have been demonstrated to have such an impact it may be registered for applicable standards and requirements irrespective of other considerations." The SDT has already received initial feedback from both NERC and FERC staffs that such a condition may exist for implementation of this standard since the effectiveness of an overall UFLS program must consider the entire load. The development of any UFLS program must include some means of providing a mutual/coordinated load shed for "smaller" entities such as agreements by "larger" entities to provide such load shedding.		
Bonneville Power Administration	Yes	BPA will have to have delegation agreements with DP's when BPA is covering their loads with BPA-UFLS relays or through other UFLS armed load in our BAA.
Response: The SDT agrees that the approach the commenter is suggesting is one appropriate way to address the needs, and thanks the commenter for their support.		
ERCOT ISO	Yes	ERCOT ISO believes the Planning Coordinator is the correct responsible entity.
Response: Thank you for your support.		

Organization	Yes or No	Question 1b Comments:
	Yes	I would defer to the opinion of the Planning Coordinators, but am wondering why the RC is not involved. As far as the TO and DP responsibility I see no problem as long as it is clear what data and load tripping is required.
Response: Reliability Coordinators are not included in this standard because this standard addresses only multi-step automatic relay tripping and load shedding that must be planned and implemented in advance. The SDT believes that Planning Coordinators are the appropriate entities for this function. Manual load shedding is not covered by this standard.		
PacifiCorp	Yes	While PacifiCorp agrees that coordination between Planning Coordinators is necessary in order to design and implement an effective UFLS program, it has some concern regarding the assignment of responsibility for compliance with this standard to a currently undefined group of Planning Coordinators. There is no such entity in the Functional Model and it is therefore unclear as to how this group will function and by whom it will be governed. The way the standard is currently drafted raises significant questions regarding how the requirements will be enforced, how a Planning Coordinator will know what group to participate in, how its participation in such group will be evaluated, how disagreements between group participants will be resolved, and which entity, among such group of Planning Coordinators, will be responsible for any potential violations. PacifiCorp recommends that either 1) the SDT assign the UFLS coordination responsibility and governance to the Regional Entity; or 2) the SDT re-draft the standard in such a way that allows Planning Coordinators to assign their compliance responsibility and activity to an agent Planning Coordinator Group similar to the group concept utilized in BAL-002-0 that allows Balancing Authorities to assign compliance responsibility to a Reserve Sharing Group.
Response: Thank you for your comment. The SDT has removed the group of Planning Coordinators concept from the standard. The applicability has been changed to individual Planning Coordinators.		
NIPSCO	Yes	The planning groups yes
Response: Thank you for your support.		
Pepco Holdings, Inc – Affiliates	Yes	
Electric Market Policy	Yes	
Edward C. Stein	Yes	
Colmac Clarion	Yes	

Organization	Yes or No	Question 1b Comments:
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
US Army Corps of Engineers	Yes	
Public Service Electric and Gas Company	Yes	
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
ReliabilityFirst Corporation	Yes	
System Protection & Control	Yes	
Ontario Power Generation	Yes	
Luminant Power	Yes	
NextEra Energy Resources, LLC		No comment.

2. The SDT has strived to draft the applicability in a manner that includes all load while avoiding assigning applicability to more than one entity for the same load. The Functional Model indicates the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. Considering the Functional Model definition of Distribution Providers please indicate whether you believe it is necessary to assign applicability to "Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of a Distribution Provider's load".

Summary Consideration: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.

Organization	Yes or No	Question 2 Comments:
Northeast Power Coordinating Council	No	Based on the definition of Distribution Provider in the Functional Model we believe that the applicability should be limited to Distribution Providers. All load should be accounted for by a registered Distribution Provider. The standard should not be written to correct for deficiencies resulting from incorrect registration of entities, and proper registration is vital to the reliability of the UFLS program.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Southern Company	No	The applicability should be assigned to the TO only (not to DP). The Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate, if they choose, to implement the UFLS scheme providing the most selective load tripping, while at the same time, allowing for more efficient aggregation of smaller DPs' load into the overall scheme.

Organization	Yes or No	Question 2 Comments:
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Electric Market Policy	No	The definition of Distribution Provider is adequate.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Midwest ISO Stakeholders Standards Collaborators	No	We do not believe it is necessary to assign applicability to Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of the Distribution Providers load. We believe this clause is describing a distribution provider and these TOs should be registered as DPs. Furthermore, Standards should not attempt to create new classifications of registered entities. This is the function of the compliance registration process.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
SERC UFLS Standards Drafting Team	No	The applicability should be assigned to the TO only (not to DP). The Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.

Organization	Yes or No	Question 2 Comments:
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
MRO NERC Standards Review Subcommittee	No	The MRO NSRS believes that the definition of Distribution Provider assures that there are no gaps or holes in coverage of the applicable load. As noted in the response to Question 1, it is unnecessary to also assign applicability to Transmission Owners with end-use Load connected to their Facilities because according to the NERC Compliance Registry Criteria Rev 5.0 (Sections II.b and III.b.2) these entities must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Kansas City Power & Light	No	No, it is not necessary to include Transmission Provider with end-use load.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
IRC Standards Review Comittee	No	NERC standards and requirements should not attempt to further define the functional entities. For those transmission owners that have facilities that meet the NERC definition of Distribution Provider, they should be registered in the compliance registry as such. If the interpretation of the current definition is that it does not include Transmission Owners with end-use Load connected to their facilities, we recommend the definition of Distribution Provider be updated.The Functional Model does not preclude assigning this responsibility to the Transmission Owners with end-use Load connected to their facilities where such end-use load is not part of a Distribution Provider's load. Excerpt

Organization	Yes or No	Question 2 Comments:
		from Chapter 14 of the Version 4 Functional Model Technical Document, below, describes this process:[When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedance of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.]Loads that are connected to the transmission facilities and where such loads are not part of the DP's loads can and should be curtailed by the TOP action (to relieve constraints) or by the UFLS relays provided by the TOs (to arrest frequency decline).If the SDT is still undecided on this issue, we suggest the SDT consult the FMWG
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Public Service Electric and Gas Company	No	The Distribution Provider can in most cases identify all the load that is included in the UFLS Program.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Central Lincoln	No	But please see Q1b comments.
Response: Please see the response to Q1b comments.		
SPP System Protection and Control Working Group	No	For those transmission owners that have facilities that meet the NERC definition of Distribution Provider, they should be registered in the compliance registry as such.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance		

Organization	Yes or No	Question 2 Comments:
Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Long island power Authority	No	
ReliabilityFirst	No	The Transmision Owner with end use load connected ... is out of line with the NERC Functional Model knowing that if a Transmision Owner has end use load connected, by definition, the Transmision Owner must register as a Distribution Provider. Therefore, using just the Distribution Provider in the UFLS standard is adequate and complete.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Illinois Municipal Electric Agency	No	IMEA believes it is not necessary to assign applicability to the TO function since the NERC Statement of Compliance Registry Criteria (Revision 5.0) already specifies that for end-use customers who are served at transmission voltages, the TO also serves as the DP (i.e., such a TO should already be registered as a DP).
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
American Transmission Company	No	As noted in the response to Question 1, per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner with end-use load connected to their facilities must register as a Distribution Provider or transferred the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. So, all applicable end-use load will be covered by the standard and the assignment of applicability to Transmission Owners with end-use load connected to their facilties is superflous and redundant.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers		

Organization	Yes or No	Question 2 Comments:
and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Hydro-Québec TransEnergie (HQT)	No	Based on the definition of Distribution Provider in the Functional Model we believe that the applicability should be limited to Distribution Providers. All load should be accounted for by a registered Distribution Provider. The standard should not be written to correct for deficiencies resulting from incorrect registration of entities, and proper registration is vital to the reliability of the UFLS program.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
FirstEnergy Corp	No	The Distribution Provider sufficiently covers the end-use load subject to UFLS requirements and we do not believe the Transmission Owner needs to be included within the applicability of this standard.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
CenterPoint Energy	No	For many years, CenterPoint Energy has complied with regional UFLS criteria for distribution load tripping. CenterPoint Energy does not believe it is necessary to include any requirements within PRC-006 for applicability to Transmission Owners and, therefore, recommends deleting Transmission Owner from Requirements 9 and 10. CenterPoint Energy commends the SDT for addressing the difficult issue of Applicability. By definition, Transmission Owners do not serve any load, whether distribution voltage or end-use transmission voltage. There may also be legalities that can preclude a Transmission Owner from serving any load. It would be problematic for a Transmission Owner to determine what transmission end-use load to trip when such loads can be refineries, chemical plants, water plants, and national space agency facilities. Tripping of such loads may have environmental and safety impacts. In addition, a Transmission Owner may not have any ownership of a transmission voltage end-use facility, nor control

Organization	Yes or No	Question 2 Comments:
		over such a facility. CenterPoint Energy believes the NERC Functional Model correctly reflects that Distribution Providers, not Transmission Owners, would be the responsible entity for load tripping.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Xcel Energy	No	We feel 4.3 should be removed.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
We Energies	No	
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes the applicable entities provided for in the proposed standard are appropriate. However, the TRE UFLS SDT believes that the only group that may not be clearly understood to have assigned applicability are self-served customers that can shut down generation and pull from the grid without activating their own underfrequency load shedding. Assigning applicability to Transmission Owners with end-use load may make this clearer but we are not sure it is clear enough for self-served industrials. Additional specific wording to address this may be needed.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. **However, the SDT does not believe that including Transmission Owners in the Applicability clarifies responsibilities for self-served customers. The SDT believes that, from a NERC Reliability Standard perspective, such customers must be addressed and included in an effective UFLS program.**		

Organization	Yes or No	Question 2 Comments:
The SDT is unaware of any provision for such customers to be exempt from functional registration by the Regional Entity. With regard to coordination of generation tripping by frequency level or with regard to load tripping by frequency level, such installations are equally important with regard to their potential impact upon the reliability of the bulk power system.		
Pepco Holdings, Inc - Affiliates	Yes	PHI agrees that including the Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load eliminates the ambiguity that could result if Transmission Owners were not included in the Applicability list.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Bonneville Power Administration	Yes	It addresses DSI and other large loads that are directly connected to the BES.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
ERCOT ISO	Yes	All loads within the region should be accounted for when designing an UFLS program.
Response: The SDT agrees and intends that all load be covered. Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
FRCC Standards & Operations	Yes	We believe that it is necessary to assign applicability to 'Load Serving Entities'. The Compliance Registry Criteria states: Load-serving entity is designated as the responsible entity for facilities that are part of a required

Organization	Yes or No	Question 2 Comments:
Departments		underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system. Therefore their applicability is appropriate.In addition we recommend adding a caveat within the applicability section that reads The TO, LSE or DP may meet these requirements through participation in an aggregated UFLS Program as permitted by the Regional UFLS program. This would allow smaller systems to aggregate load requirements and more effectively meet Regional UFLS requirements. Furthermore, we recommend an additional caveat within the applicability section that reads, "Compliance with an approved Regional Reliability Standard which defines the requirements of the Regional UFLS program satisfies the compliance requirements associated with this continent wide standard." This assumption can be made based on the defined attributes of a Regional Reliability Standard (i. e. Regional Reliability Standards go beyond, add detail to, or implement NERC Reliability Standards. Regional Reliability Standards shall not be inconsistent with or less stringent than NERC Reliability Standards.).
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. The interim changes to the NERC Statement of Compliance Registry were made to reflect concerns about the definition of the LSE as a "facility owning entity" as opposed to the Distribution Provider. As demonstrated in the NERC LSE workshop, currently approved Functional Model and the interim Registry Criteria changes, for standards purposes the DP is the "wires" connection to the electric system and owner of the UFLS tripping equipment. This may be inconsistent with previous usage of the same terms in some parts of the country. The Version 0 applicability for UFLS was set prior to the Registry and determined on the then general understanding of the Functional Model and industry usage. The current Functional Model is much clearer on this issue and designates the DP as the facility owner. Since NERC has stated that the Registry Criteria now has an interim step to correct the issue, it is expected that the Registry Criteria will change as the standards are re-evaluated for appropriateness. The SDT believes that this standard is in line with the direction taken by the interim changes and the approved Functional Model. **The applicability of one standard does not reference another; each standard when approved by FERC or other governmental authorities stands on its own merit. The development of a continent wide standard does not prohibit the development of a regional standard. It is up to the region to decide whether a regional standard can be justified or if a regional variance is appropriate.**		
Florida Municipal Power Agency and Select Members	Yes	Yes, we agree, but, want to be sure the implications are understood. As written, it would seem that the proposed language would make Transmission Owners responsible for adding up the load connected to their system, and if the total load scheduled to trip by UFLS does not meet the percentage of total load connected to that TO required, then, the TO would seem to be the ones responsible for making up the difference. We have to call into question whether

Organization	Yes or No	Question 2 Comments:
		capturing all of the load is worth the effort and whether it truly makes a significant difference to the reliability of the Bulk Electric System.We would suggest the added flexibility of including Load Serving Entities (LSEs) to the applicability section as well as including the ability for LSEs to represent multiple Distribution Providers. The Compliance Registry Criteria states: Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system. Therefore their applicability is appropriate.In addition we recommend adding the ability to aggregate within the applicability section that reads The LSE or DP may meet these requirements through participation in an aggregated UFLS Program. This would allow small systems to aggregate load requirements and more effectively meet Regional UFLS forecast load tripping requirements. The aggregation provides better resolution to the Regional plan requirements. Or alternatively, create a new function that allows aggregation similar to a Reserve Sharing Group.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. The interim changes to the NERC Statement of Compliance Registry were made to reflect concerns about the definition of the LSE as a "facility owning entity" as opposed to the Distribution Provider. As demonstrated in the NERC LSE workshop, currently approved Functional Model and the interim Registry Criteria changes, for standards purposes the DP is the "wires" connection to the electric system and owner of the UFLS tripping equipment. This may be inconsistent with previous usage of the same terms in some parts of the country. The Version 0 applicability for UFLS was set prior to the Registry and determined on general understanding of the Functional Model and industry usage. The current Functional Model is much clearer on this issue and designates the DP as the facility owner. Since NERC has stated that the Registry Criteria now has an interim step to correct the issue. It is expected that the Registry Criteria will change as the standards are re-evaluated for appropriateness. The SDT believes that this standard is in line with the direction taken by the interim changes and the approved Functional Model.		
Cowlitz County PUD	Yes	Yes, but for a different reason: many times the TO will be the owner of the UFLS equipment (e.g. Bonneville Power Administration), not the DP. There are many DP's who do not own UFLS equipment and should not be forced in this position if there is a willing TO to take on the responsibility.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. The Statement of Compliance Registry Criteria can permit small		

Organization	Yes or No	Question 2 Comments:
Distribution Provider exemption from registration and therefore exclusion from implementing UFLS apart from the applicability of this standard.		
Exelon	Yes	Need to verify all end use load participates regardless of supply voltage level.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
AEP	Yes	This is a useful method for identifying those TOs where this situation occurs, instead of making the standard unnecessarily apply to all TOs.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
PacifiCorp	Yes	The simulations done by a group of Planning Coordinators must include all load in designing the UFLS program. However, there should be no obligation that all entities be required to shed any of their load at any particular frequency as long as sufficient load is shed in the area under study. The UFLS program could exempt Distribution Providers with peak loads less than an agreed upon threshold from shedding any load as long as sufficient load is shed in the area under study.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. The Statement of Compliance Registry Criteria can permit small Distribution Provider exemption from registration and therefore exclusion from implementing UFLS apart from the applicability of this standard.		
Ameren	Yes	There may be loads that have no association or relationship with a Distribution Provider that would allow their load to

Organization	Yes or No	Question 2 Comments:
		be interrupted and thus be considered for the UFLS program.
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program. The SDT assumes that the loads the commenter refers to are served by Transmission Owners.		
Independent Electricity System Operator	Yes	We agree that it is necessary to assign applicability to Transmission Owners with end-use Load connected to their facilities where such end-use load is not part of a Distribution Providers load. This assignment is in principle consistent with the perceived process presented in the Functional Model pertaining to the Transmission Operator having a role to curtail loads that are under its control to relieve transmission constraint. Excerpt from Chapter 14 of the Version 4 Functional Model Technical Document, below, describes this process:[When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedence of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.]Loads that are connected to the transmission facilities and where such loads are not part of the DPs loads can and should be curtailed by the TOP action (to relieve constraints) or by the UFLS relays provided by the TOs (to arrest frequency decline).
Response: Industry comments suggest the entity that presently implements UFLS varies among regions and includes both Distribution Providers and Transmission Owners. The SDT believes that the Distribution Provider, as the entity that connects end-user load to the electrical system, has primary responsibility for implementing UFLS. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. However, the SDT also recognizes that many Transmission Owners provide implementation of UFLS under agreement with a Distribution Provider. The SDT has revised the applicability to include both Distribution Providers and Transmission Owners as UFLS entities that may be designated by Planning Coordinators to implement a UFLS program.		
Colmac Clarion	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
US Army Corps of	Yes	

Organization	Yes or No	Question 2 Comments:
Engineers		
NIPSCO	Yes	
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	Yes	
System Protection & Control	Yes	
Ontario Power Generation	Yes	
Luminant Power	Yes	
NextEra Energy Resources, LLC		No comment.

3. The proposed continent-wide standard requires that Planning Coordinators model the trip settings of any generators that trip at or above 58.0 Hz (Requirement R8) when verifying through dynamic simulation that the UFLS program design is adequate to meet the continent-wide performance characteristics specified in Requirement R6.

Do you agree with this approach to ensure that effectiveness of the UFLS program is not jeopardized by units that trip at or above the minimum frequency (58.0 Hz) at which the UFLS program may arrest frequency decline?

Summary Consideration: Most commenters agree that modeling trip settings of generating units is an acceptable approach to ensure that effectiveness of the UFLS program is not jeopardized by units that trip at or above the frequency at which the UFLS program is designed to arrest frequency decline. Some commenters suggested that determining the units to model based only on a frequency threshold would include units unnecessarily. In response to some comments and further SDT deliberations, the standard has been modified to specify, for assessment modeling purposes, generator tripping boundaries as proposed in PRC-024-1, Attachment 1, for which the 58.0 Hz threshold was originally meant as a proxy. Temporary frequency excursions below the UFLS program set points and time delays could occur and the SDT wants to be sure that the assessments do not overlook any generator trip settings just below UFLS set points or just beyond the UFLS relay time delay settings that may still be reached. The standard has been modified to require, in the assessments per R4, the modeling of generator trip settings according to curves as shown in Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1.

Some commenters expressed concern regarding Planning Coordinators maintaining data on generators with trip settings that do not meet the requirements proposed in PRC-024. The SDT notes that per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under- and over-frequency trip settings that fall outside the acceptable boundaries defined by PRC-024-1, Attachment 1 and may include this information in their database. The SDT agrees with commenters that the Generator Owner is already required by draft PRC-024-1 to supply this information to the Planning Coordinator and has removed this requirement from the draft standard.

Organization	Yes or No	Question 3 Comments:
SPP System Protection and Control Working Group	No	What is the basis for 58.0 Hz? If the region's lowest UFLS setting is designed for 58.7 Hz, is 58.0 Hz requirement critical from the Regional UFLS program point of view?
Response: The SDT chose 58.0 Hz as the minimum frequency to observe for purposes of designing a regional UFLS program. This value also coordinates with the under-frequency generator trip curve in PRC-024-1 currently under draft. If a region's lowest UFLS stage is 58.7 Hz, then 58.0 Hz may not be critical. However, it is possible that temporary frequency excursions below the UFLS program set points and time delays could occur and the SDT wants to be sure that the assessments do not overlook any generator trip settings just below UFLS set points or beyond the UFLS relay		

Organization	Yes or No	Question 3 Comments:
settings that may still be reached. Note that the standard has been modified to require, in the UFLS assessments per R4, the modeling of generator trip settings according to curves as shown in Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1.		
MRO NERC Standards Review Subcommittee	No	[This question actually applies to Requirement R7, not R8.]We agree that PCs should model the trip settings of any generators that may be tripped during the simulated operation of the UFLS program. However, the applicable generator trip settings may vary depending on the set points and time delays of the underfrequency relays of the UFLS program for a given island. We suggest that R7.1 be reworded to "that trip at or above the minimum frequency set points and time delays of the applicable island's UFLS program". This approach gives consideration to the time delay aspect and allows the frequency limit to be higher (or lower), if it is permitted by the applicable island's UFLS program.We suggest similar rewording for R7.2, "that trip at or above the maximum frequency set points and time delays of the applicable island's UFLS program".On a related matter, the existing Requirement R7 states "conduct a UFLS assessment . . . through dynamic simulations". Therefore, we suggest that the following rewording for R7, "shall conduct a UFLS assessment . . . that determines whether the UFLS program design meets . . . R6. The assessment shall include: " This would allow other analytical methods, such as the Equivalent Inertia Analysis, to be used to perform an appropriate UFLS assessment. The Equivalent Inertia method can also be used to check for proper coordination between the underfrequecy relay settings and the generator trip settings. R7.1 "Analysis of the trip settings of any generators that . . ."R7.2 "Analysis of the trip settings of any generators that . . ." R7.3 "Analysis of any automatic load restoration that . . ."See response to comment 8 regarding the 58 Hz limit.
Response: The SDT apologizes for the incorrect reference to R8. The SDT agrees with your principle and has modified the standard to be more specific on what generator trip settings must be modeled. Temporary frequency excursions below the UFLS program set points and time delays could occur and the SDT wants to be sure that the assessments do not overlook any generator trip settings just below UFLS set points or just beyond the UFLS relay time delay settings that may still be reached. The standard has been modified to require, in the UFLS assessments per R4, the modeling of generator trip settings according to curves as shown in Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1. Nothing in the standard precludes the use of Equivalent Inertia Analysis in the UFLS design process, but the SDT believes that dynamic simulations are the most dependable means of assessing compliance to the performance characteristics. Equivalent inertia analysis would not include the effects of island initiating disturbances on localized frequency and voltage, inter-machine oscillations, or the particular response of individual unit governors.		
Kansas City Power & Light	No	This question is actually referring to requirement R6. What is the engineering basis for 58Hz? The frequency threshold should be based on the prevention of damage to generating equipment, operating equipment, customer loads, etc. Regardless of frequency threshold, all generator protection settings that involve frequency and voltage should be modeled in the simulation studies for UFLS programs.
Response: The SDT apologizes for the incorrect reference to R8. The engineering basis is coordination of UFLS programs with generator tripping. R6 (now R3) establishes UFLS program requirements that coordinate with the acceptable generator tripping boundary defined by PRC-024-1, Attachment 1. Assessments of UFLS program designs are required to model generator trip settings that fall outside the acceptable boundary		

Organization	Yes or No	Question 3 Comments:
specified in PRC-024-1. Note that the standard has now been modified to define curves above and below which generator underfrequency and overfrequency protection, respectively, must be modeled. These curves are the same as the proposed curves in PRC-024-1, Attachment 1. Please see R4 and Attachments 1 and 2. The SDT disagrees that it is necessary to require in this standard that protection settings involving voltage need to be modeled in UFLS assessments, though that may be advisable when simulating islanding scenarios resulting from severe disturbances.		
Colmac Clarion	No	Some U/F setpoints currently in use above 58.0 Hz were mandated by Generator OEM vice Transmission Operator. All U/F setpoint 'mandates' should be made not to violate design setpoints for specific generators OEM requirements when conducting analysis of setpoints.
Response: The proposed standard does not preclude settings above 58.0 Hz; it only requires such settings be modeled by the Planning Coordinators in their UFLS assessments. Please refer to Project 2007-09 and PRC-024-1 for requirements on generator under-frequency settings.		
US Army Corps of Engineers	No	Without actually testing the UFLS, how do you know that the simulation testing adequately represents real world events? There needs to be more concrete assurance or testing of the generation side to show that the unis will not trip off. I realize that this assurance should be covered under the MOD Reliability Standards, but I don't think it has been completely addressed.
Response: There is always a question about how well simulation studies represent the real world. Model validation and event replication studies over several decades have increased industry confidence that simulation studies can, in principle, reasonably represent the dynamic behavior of real world power systems. As with any study, assumptions need to be carefully reviewed and validated. The SDT is aware that causes other than frequency-sensing relays may also trip generation outside the acceptable tripping boundaries being proposed in draft PRC-024-1, Attachment 1. Unfortunately, you are right in that this possibility is not being addressed in this standard. The SDT recommends that this matter be brought to the attention of the Project 2007-09, Generator Verification SDT responsible for PRC-024-1.		
NIPSCO	No	The existing trip points with out time delay is 58.2 - To protect against turbine blade damage.I believe any under frequency event that allows the frequency to get to 58 HZ is to late/ and to slow.
Response: The SDT disagrees. While it is true that ECAR Document 3 listed 58.2 Hz as the point to expect immediate generator tripping, according to major generator manufacturer's documents, generators can tolerate frequency excursions for limited time below this level. Please refer to Project 2007-09 and PRC-024-1.		
Public Service Electric and Gas Company	No	No, however, while the effort to determine if the UFLS program is effective if generators trip at or above a minimum frequency, we are not sure that any simulations are accurate enough to validate this. Every event is different, but if it can be accurately modeled, then it is a good approach.
Response: There is always a question about how well simulation studies represent the real world. Model validation and event replication studies		

Organization	Yes or No	Question 3 Comments:
over several decades have increased industry confidence that simulation studies can, in principle, reasonably represent the dynamic behavior of real world power systems. As with any study, assumptions need to be carefully reviewed and validated.		
American Transmission Company	No	[This question actually applies to Requirement R7, not R8.]We agree that PCs should model the trip settings of any generators that may be trip during the simulated operation of the UFLS program. The applicable generator trip settings will depend on the set points and time delays of the underfrequency relays in the UFLS program. We suggest that R7.1 be reworded to "that trip at or above the minimum frequency set points and time delays of the applicable island's UFLS program". This approach gives consideration to the time delay aspect and allows the frequency limit to be higher (or lower), if it is permitted by the applicable island's UFLS program.We suggest similar rewording for R7.2, "that trip at or above the maximum frequency set points and time delays of the applicable island's UFLS program".On a related matter, the root Requirement R7 states "conduct a UFLS assessment . . . through dynamic simulations". However, other analytical methods, such as Equivalent Inertia Anaysis, can also be used to perform an appropriate UFLS assessment and may check for proper coordination between the underfrequecy relay settings and the generator trip settings. Therefore, we suggest that the following rewording for R7, "shall conduct a UFLS assessment . . . that determines whether the UFLS program design meets . . . R6. The assessment shall inlcude:"R7.1 "Analysis of the trip settings of any generators that . . ."R7.2 "Analysis of the trip settings of any generators that . . ." R7.3 "Analysis of any automatic load restoration that . . ."See the response to Question 8 for comment on the 58.0 Hz and 61.8 Hz limits.
Response: The SDT apologizes for the incorrect reference to R8. The SDT agrees with your principle and has modified the standard to be more specific on what generator trip settings must be modeled. Temporary frequency excursions below the UFLS program set points and time delays could occur and the SDT wants to be sure that the assessments do not overlook any generator trip settings just below UFLS set points or just beyond the UFLS relay time delay settings that may still be reached. The standard has been modified to require, in the UFLS assessments per R4, the modeling of generator trip settings according to curves as shown in Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1. Nothing in the standard precludes the use of Equivalent Inertia Analysis in the UFLS design process, but the SDT believes that dynamic simulations are the most dependable means of assessing compliance to the performance characteristics in R6. Equivalent inertia analysis would not include the effects of island initiating disturbances on localized frequency and voltage, inter-machine oscillations, or the particular response of individual unit governors.		
FirstEnergy Corp	No	The Planning Coordinator should be required to model somewhat below the 58.0 Hz level, we suggest down to 57.5 Hz, so that a sensitivity analysis is performed evaluating the severity of frequency disturbance that is not fully arrested at or above the 58 Hz level. This information could be used to assess if additional load dropping may be needed for more severe frequency events.
Response: The standard has been modified to address your comment. The SDT has defined curves above and below which generator underfrequency and overfrequency protection, respectively, must be modeled. See R4 and Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1. As such, the minimum generator trip threshold that must be modeled is now 57.8 Hz, which the SDT		

Organization	Yes or No	Question 3 Comments:
believes provides adequate margin.		
IRC Standards Review Committee	Yes	We agree but we think you meant R7, not R8. And assuming that the expected loss of generation (for generators tripping at or above 58.0 Hz) is to be compensated by selecting an additional, equivalent amount of load in the UFLS program, the additional load reduction would also need to be simulated.
Response: Thank you for your support. The SDT apologizes for the incorrect reference to R8. The SDT agrees that any extra load shedding necessary for the UFLS program to comply with the performance characteristics in R6 (now R3) would need to be simulated.		
Cowlitz County PUD	Yes	This seems fair to me. There is no mandate not to allow trip settings above 58 Hz, but there must be very good reasons for such settings, and that such settings will not require greater than necessary load shedding efforts to stabilize the BPS. DPs and LSEs are sensitive to reliable service to their customers. Unnecessary load shedding would add insult to injury.
Response: Thank you for your support. Per R5 and R6 of the first draft of PRC-024-1, Generator Owners will need to document, subject to peer review, any generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1.		
Independent Electricity System Operator	Yes	We agree but I think you meant R7, not R8. And assuming that the expected loss of generation (for generators tripping at or above 58.0 Hz) is to be compensated by selecting an additional, equivalent amount of load in the UFLS program, the additional load reduction would also need to be simulated. If this requirement is to be added, depending on how this is to be complied with the Applicability Section may need to be expanded.
Response: Thank you for your support. The SDT apologizes for the incorrect reference to R8. The SDT agrees that any extra load shedding necessary for the UFLS program to comply with the performance characteristics in R6 (now R3) would need to be simulated. The applicability section does not need to be expanded because Planning Coordinators would still be the applicable entities to demonstrate compliance with R4 in R5.		
Xcel Energy	Yes	The dynamic simulation would need to include any small generators (<20MVA or <75MVA aggregate) that are not required to register, but together, could have a material impact on the BES. Additionally, it would need to be clear who is responsible for ensuring those material impacts are included in models/simulations.
Response: Thank you for your support. Although there are differing views on this question, the SDT has decided that it is sufficient to require the modeling of generator trip settings on small generators consistent with the NERC Statement of Compliance Registry Criteria. Please see R4. The Planning Coordinators are the responsible entity for ensuring that material impacts are included in UFLS assessments per R4 and R5.		
TRE UFLS Standard Drafting Team	Yes	It would appear to be essential that the Planning Coordinators data base include trip settings and time delay to tripping for resources that trip above the 58.0 Hz point. The effective simulation and design of a regional UFLS plan must

Organization	Yes or No	Question 3 Comments:
		definitively show the targeted islanding of the region. By not including the modeling of the trip points and time delays for machines that trip above 58.0, Hz, the Planning Coordinator cannot ensure the simulation and plan for effective and survivable islands that can be forecasted to exist post separation. The time criteria in R6.2, particularly the first two cumulative steps, require the effective modeling of machines set to trip above 58.0 Hz.
Response: Thank you for your support. Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1, and may include this in their database. Note that the standard has been modified to require, in the UFLS assessments per R4, the modeling of generator trip settings according to curves as shown in Attachments 1 and 2. These curves are the same as the proposed curves in PRC-024-1, Attachment 1.		
Southern Company	Yes	The generators must be modeled to reflect the way they perform.
Response: Thank you for your support.		
ERCOT ISO	Yes	ERCOT ISO believes it is necessary to consider all automatic tripping schemes or protection schemes when designing an UFLS program to meet the requirements of this standard. However, explicit modeling of generator frequency trip settings (above 58.0Hz/below 61.8Hz) should only be required when they are relevant to satisfying the performance requirements of the standard (i.e. if generator trips are initiated for excursions lasting less than 30 seconds).
Response: Thank you for your support. The standard has been modified to address your comment by defining curves above and below which generator underfrequency and overfrequency protection, respectively, must be modeled. These curves are the same as the proposed curves in PRC-024-1, Attachment 1. Please see R4 and Attachments 1 and 2.		
Midwest ISO Stakeholders Standards Collaborators	Yes	Generation owners certainly have the right to set relays to protect their equipment from damage and are actually speeding restoration by doing so. Any units that will trip before frequency triggers UFLS relays should certainly be considered in the dynamic simulations.
Response: Thank you for your support.		
Luminant Power	Yes	Luminant agrees with the UFLS SDT that the Planning Coordinators should model the generators that would trip at or above 58.0 Hz, as required by R7. However, Requirement R8 of PRC-006 requires the Planning Coordinator to maintain a database of relay information only from Transmission Owners and Distribution Providers. The Planning Coordinator database in Requirement R8 should also include relay information from Generator Owners. The UFLS SDT does not need to include a requirement in PRC-006 for Generator Owners to provide the information, as the draft NERC Standard PRC-024 requires Generator Owners to provide frequency and voltage relay setting information to the Planning Coordinator.

Organization	Yes or No	Question 3 Comments:
Response: Thank you for your support. Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. The SDT agrees that the Generator Owner is already required by draft PRC-024-1 to supply this information to the Planning Coordinator and has removed this requirement from the draft standard.		
Ameren	Yes	Yes, such generators should have their trip settings modeled to determine the additional load that must be shed because they do not meet performance characteristics. The cost to include this additional load shed should be allocated to these generators.
Response: Thank you for your support. Cost allocation is outside the scope of reliability standards.		
SERC UFLS Standards Drafting Team	Yes	he generators must be modeled to reflect the way they perform.
Response: Thank you for your support.		
Hydro-Québec TransEnergie (HQT)	Yes	See also our answer to Q8 in regards to the minimum frequency treshold.
Response: Thank you for your support.		
AEP	Yes	Please note that the reference to R8 in the question appears to an error.
Response: Thank you for your support. The SDT apologizes for the incorrect reference to R8.		
Pepco Holdings, Inc – Affiliates	Yes	
Bonneville Power Administration	Yes	
Northeast Power Coordinating Council	Yes	
Electric Market Policy	Yes	

Organization	Yes or No	Question 3 Comments:
FRCC Standards & Operations Departments	Yes	
Florida Municipal Power Agency and Select Members	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
Central Lincoln	Yes	
Long island power Authority	Yes	
Exelon	Yes	
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	Yes	
System Protection & Control	Yes	

Organization	Yes or No	Question 3 Comments:
ReliabilityFirst	Yes	
Ontario Power Generation	Yes	
We Energies	Yes	
PacifiCorp	Yes	
NextEra Energy Resources, LLC	Yes	

4. The SDT added a requirement that requires the Planning Coordinators model, in the five year assessments, any automatic load restoration that is designed to assist in stabilizing system frequency (Requirement R9). The team decided to add this requirement as a result of a comment during the first posting. Do you agree that this requirement is necessary for reliability?

Summary Consideration:

Most entities support this requirement.

Some want exceptions to be allowed to exclude this modeling from the program design if the automatic load restoration is "insignificant". Some feel this requirement does not go far enough to include ***ALL*** automatic load restoration schemes which may impact UFLS, not just the ones ***designed*** to impact UFLS. The SDT believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled. The SDT modified the requirement (now Requirement R4, Part 4.7 in the revised standard) from "any automatic load restoration that is designed to assist in stabilizing frequency" to "any automatic load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment."

Some feel that automatic load restoration is generally a bad idea for use with UFLS. The SDT noted that the proposed standard does not require the use of automatic load restoration schemes and acknowledges this may not be a practical method to stabilize some systems. However, where automatic load restoration schemes are utilized a failure to consider them in assessments of the UFLS program design may result in unintended consequences during actual UFLS events. The SDT included modeling of automatic load restoration in UFLS program assessments to identify any unintended consequences of using automatic load restoration.

Organization	Yes or No	Question 4 Comments:
Alabama Municipal Electric Authority	No	If the automatic load was induced by inductors I would have voted yes because this is part of good planning. I voted "no" because there is no way to determine or predict that "all" of the load for a load restoration activity would be "available" if the automatic load restoration was for user or customer load.
Response: The SDT makes no reference to the origination of the load to be included for automatic restoration in the UFLS program design. Where such automatic load restoration is utilized, the Planning Coordinators are required to model, in their UFLS program assessments, the actual scheme as implemented.		
Public Service Electric and Gas Company	No	It would not seem practical to consider automatic load restoration as a method to stabilize a system.

Organization	Yes or No	Question 4 Comments:
Response: The SDT is not requiring the use of automatic load restoration schemes and acknowledges this may not be a practical method to stabilize some systems. However, where automatic load restoration schemes are utilized a failure to consider them in assessments of the UFLS program design may result in unintended consequences during actual UFLS events.		
Ameren	No	Each region should be required to identify the amount of automatic load restoration in their region that is designed to assist in stabilizing system frequency. If the region determines that this amount is insignificant and will not materially impact the design of the region's UFLS program, then they should be allowed to exclude this load from their simulations.
Response: The SDT believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled.		
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes that successful deployment of a UFLS is dependent on two concepts. The first is automatic reaction of the UFLS when frequency triggers its response to dump load. The second is load shall not be brought back until the Reliability Coordinator instructs each entity to do so in whatever order is appropriate for adequate recovery. Therefore modeling of any applicable automatic load restoration should be included in a region's UFLS program.
Response: Thank you for your support.		
Bonneville Power Administration	Yes	It addresses automatic load restoration for frequency over-shoot.
Response: Thank you for your support.		
Northeast Power Coordinating Council	Yes	We believe that any automatic action that impacts recovery and stabilization of frequency must be modeled.
Response: Thank you for your support.		
Southern Company	Yes	Yes, but with the ability to specify exceptions. Each regional entity should be required to identify the amount of automatic load restoration in their region that is designed to assist in stabilizing system frequency. If the region determines that this amount is insignificant (e.g. 1%) and will not materially impact the design of the region's UFLS scheme, then they should be allowed to exclude this load from their simulations.
Response: The SDT believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the		

Organization	Yes or No	Question 4 Comments:
duration of the simulations run for the assessment should be modeled.		
ERCOT ISO	Yes	At this time ERCOT ISO does not know of any automatic load restoration schemes within the ERCOT Interconnection. But as previously stated in question 3, it is necessary to consider all automatic tripping schemes when developing an UFLS program to meet the requirements of this standard, and therefore ERCOT ISO agrees this is necessary.
Response: Thank you for your support.		
Electric Market Policy	Yes	However, Question 4 reference to Requirement R9 should be R7.
Response: The SDT apologizes for the incorrect reference to R9.		
Midwest ISO Stakeholders Standards Collaborators	Yes	Generally, automatic load restoration is a bad idea. It could interfere with restoration. What if too much load is restored and actually causes frequency to decline significantly?
Response: The SDT included modeling of automatic load restoration in UFLS program assessments to identify any unintended consequences of using automatic load restoration.		
SERC UFLS Standards Drafting Team	Yes	Yes, but with the ability to specify exceptions. Each regional should be required to identify the amount of automatic load restoration in their region that is design to assist in stabilizing system frequency. If the region determines that this amount is insignificant (e.g. 1%) and will not materially impact the design of the region's UFLS scheme, then they should be allowed to excluded this load from their simulations.
Response: The SDT believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled.		
MRO NERC Standards Review Subcommittee	Yes	This question actually applies to Requirement R7.3, not R9.]We agree that any automatic load restoration that is designed to assist in stabilizing the system frequency should be modeled in the ULFS Program assessment.
Response: The SDT apologizes for the incorrect reference to R9. Thank you for your support.		

Organization	Yes or No	Question 4 Comments:
IRC Standards Review committee	Yes	We agree with this requirement but believe there should be more specific language on what schemes should be included in the study. There may also be automatic load restoration schemes that have an impact on stabilizing system frequency but was not installed with that intent. The study should also consider the effects of these automatic restoration schemes. Again, we think you meant R7, not R9. We agree. Any pre-determined actions such as tripping of additional load for generator tripping at or above 58.0 Hz as discussed in Q3, above, and automatic restoration of load, etc. should be modeled and assessed via simulations to evaluate frequency performance of potential islands.
Response: The SDT believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled. **The SDT apologizes for the incorrect reference to R9.** **Thank you for your support.**		
Cowlitz County PUD	Yes	You meant Requirment R7.3? This seems to be an excellent idea to me. Anything that both stabilizes the BPS and improves on customer service is a winner.
Response: The SDT apologizes for the incorrect reference to R9. Thank you for your support.		
US Army Corps of Engineers	Yes	Modeling automatic load restoration on a 5 year cycle should capture the changes/modifications that the individual Registered Entities have done to their system. Too often the minor tweaks to a system get lost in the cracks and the cumulative modifications do have an impact on system studies.
Response: Thank you for your comments.		
SPP System Protection and Control Working Group	Yes	We agree with this requirement but believe there should be more specific language on what schemes should be included in the study. There may also be automatic load restoration schemes that have an impact on stabilizing system frequency but was not installed with that intent. The study should also consider the effects of these automatic restoration schemes.
Response: The SDT agrees and believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled.		

Organization	Yes or No	Question 4 Comments:
Exelon	Yes	It should be clear only those restoration systems designed to stabilize system frequency should be included in the standard. Requirement 9 in the proposed standard does not appear to be related to automatic load restoration systems.
Response: The SDT agrees and believes that any automatic load restoration which impacts frequency stabilization and is designed to operate within the duration of the simulations run for the assessment should be modeled. **The SDT apologizes for the incorrect reference to R9.**		
Arkansas Electric Cooperative Corporation	Yes	It stands to reason that any tripping or restoration schemes that are automatic should be modeled and included in the simulations.
Response: Thank you for your support.		
Hydro-Québec TransEnergie (HQT)	Yes	HQT believe that any automatic action that impacts recovery and stabilization of frequency must be modeled.
Response: Thank you for your support.		
AEP	Yes	Please note that we are responding in the context of requirement 7.3, not requirement 9. There appears to be a error in the requirement 9 reference.
Response: The SDT apologizes for the incorrect reference to R9.		
American Transmission Company	Yes	[This question actually applies to Requirement R7.3, not R9.] We agree that any automatic load restoration that is designed to assist in stabilizing the system frequency should be modeled in the ULFS Program assessment. On the other hand, we suggest that automatic load restoration should be avoided whenever possible.
Response: The SDT apologizes for the incorrect reference to R9. **Thank you for your support.**		
Independent Electricity System	Yes	Again, we think you meant R7, not R9. We agree.

Organization	Yes or No	Question 4 Comments:
Operator		Any pre-determined actions such as tripping of additional load for generator tripping at or above 58.0 Hz as discussed in Q3, above, and automatic restoration of load, etc. should be modeled and assessed via simulations to evaluate frequency performance of potential islands.
Response: The SDT apologizes for the incorrect reference to R9. **Thank you for your support.**		
Xcel Energy	Yes	(We assume you meant R7, not R9.)
Response: The SDT apologizes for the incorrect reference to R9.		
Kansas City Power & Light	Yes	
NIPSCO	Yes	
Central Lincoln	Yes	
Long island power Authority	Yes	
ReliabilityFirst Corporation	Yes	
System Protection & Control	Yes	
ReliabilityFirst	Yes	
Ontario Power Generation	Yes	
We Energies	Yes	

Organization	Yes or No	Question 4 Comments:
PacifiCorp	Yes	
NextEra Energy Resources, LLC	Yes	
Luminant Power	Yes	
FirstEnergy Corp	Yes	
Pepco Holdings, Inc - Affiliates	Yes	
FRCC Standards & Operations Departments	Yes	
Florida Municipal Power Agency and Select Members	Yes	
Colmac Clarion	Yes	
City of Bedford	Yes	

5. **In the first posting, the Characteristics of UFLS Regional Reliability Standards required that UFLS programs be designed to limit the potential for overexcitation (V/Hz) of power system equipment at all Bulk Electric System buses. Based on industry comments, the SDT has revised this requirement in the proposed continent-wide standard to apply only at generator buses and generator step-up transformer high-side buses associated with individual generating units greater than 20 MVA (gross nameplate rating) and generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) that are directly connected to the BES. The SDT believes this change better addresses the need to have UFLS programs designed to coordinate with protection that may trip generators during an underfrequency event. Do you agree with this change?**

Summary Consideration:

The SDT has considered industry input regarding the V/Hz performance characteristic. The majority of comments from the industry supported the changes made to this requirement in the second posting.

However, the team identified the need to make two clarifying changes to the requirement. Based on its own review of the requirement the SDT decided to remove any ambiguity as to whether modeling is required when all or only one threshold is met by combining R 6.4.1 and R6.4.2 with “OR” (now Part 3.3.1 of R3). Based on a comment the SDT also added a third threshold in Part 3.3.1 of R3 to clarify our intent to include wind generation, by adding “Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.” Thus, the applicability is limited to locations at which individual generating units greater than 20 MVA (gross nameplate rating) or generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) are directly connected to the BES or any facility consisting of one or more units that are connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT also has modified Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.

The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from conservative simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard, the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.

Organization	Yes or No	Question 5 Comments:
NIPSCO	No	4 seconds is too long.
Response: The proposed point provides 0.2 Hz margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. The SDT believes that decreasing the time to less than four seconds is not necessary to coordinate the UFLS program with the generator protection requirements in PRC-024 and would place an unnecessary burden on the group of Planning Coordinators responsible for the UFLS program design.		
Midwest ISO Stakeholders Standards Collaborators	No	Please provide the technical justification for this performance criterion. We would like to add the statement "Unless generation capability or protection warrants or allows for a lower limit" to the end of the requirement. In the MRO region, this would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load. In these areas, when shedding that much load the frequency would drop below 58.2 Hz for longer than 4 seconds. We understand the SDT wants to ensure load shedding programs achieve quick frequency recovery and minimize underfrequency exposure. However we do not feel this requirement is the right way to go about that. This type of criteria is overly specific and should not be in the NERC standard. The recently developed MRO UFLS program which sheds 30% of system load appears to meet this criteria, but the Canadian portions of MRO which have higher load shedding requirements are unlikely meet this criteria. Aggressive load shedding programs in general will probably not satisfy this requirement. Frequency recovery, overall load shedding performance, and coordination with generation protection, should all be evaluated at the regional level by those who do the technical analysis of regional load shedding programs. In addition to study work, a lot of common sense needs to be applied. Several things need to be discussed to clarify our position.
Response: This criterion was selected to provide margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. The SDT does not believe it is necessary to modify the requirement as suggested because the performance characteristics in R6 (R4 in the revised standard) of the draft PRC-006 standard would NOT apply to load-generation imbalances over 25 percent. A UFLS program capable of shedding more than 25 percent of a system's load would only need to comply with the performance characteristics up to a 25 percent load-generation imbalance. Beyond a 25 percent load-generation imbalance, the group of Planning Coordinators within a region would not be subject to these requirements and could devise other performance characteristics that would apply under load-generation imbalance scenarios greater than 25 percent. The SDT did, however, modify the underfrequency performance characteristic, as shown in the Attachment 1 Underfrequency Curves, noting that some entities could have difficulty recovering frequency within 30 seconds with a 25 percent imbalance. This modification to the performance characteristic still maintains a 0.2 Hz margin with the generator tripping limitations proposed by the Generator Verification STD. **The SDT understands the concern over bigger sub-regional UFLS programs. The SDT recognizes that Planning Coordinators in a region with a 60 percent capable UFLS program, for example, may have trouble complying with the performance characteristics even under a 25 percent load-generation imbalance scenario. The SDT is not convinced that it would be impossible to comply, but can see that it could be more difficult.**		

Organization	Yes or No	Question 5 Comments:
Assessments that demonstrate the reliability objective of PRC-006 can be met without meeting the performance characteristics in Requirement R6 (R4 in the revised standard) could be used to support a request for a regional variance.		
MRO NERC Standards Review Subcommittee	No	Please provide the technical justification for this performance criteria. We suggest the addition of the statement "Unless generation capability or protection warrants or allows for a lower limit" to the end of Requirement R6.2. In the MRO region, this qualification would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load to achieve reasonable frequency recovery in these islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable. On a related note, we suggest the addition of the statement "Unless generation capability or protection warrants or allows for a higher limit" to the end of Requirement R6.3, if the impacts of island equipment are acceptable.
Response: This criterion was selected to provide margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. The SDT does not believe it is necessary to modify the requirement as suggested because the performance characteristics in R6 of the draft PRC-006 standard (R4 in the revised standard) would NOT apply to load-generation imbalances over 25 percent. An UFLS program capable of shedding more than 25 percent of a system's load would only need to comply with the performance characteristics up to a 25 percent load-generation imbalance. Beyond a 25 percent load-generation imbalance, the group of Planning Coordinators within a region would not be subject to these requirements and could devise other performance characteristics that would apply under load-generation imbalance scenarios greater than 25 percent. The SDT did, however, modify the underfrequency performance characteristic, as shown in the Attachment 1 Underfrequency Curves, noting that some entities could have difficulty recovering frequency within 30 seconds with a 25 percent imbalance. This modification to the performance characteristic still maintains a 0.2 Hz margin with the generator tripping limitations proposed by the Generator Verification STD. **The SDT understands the concern over bigger sub-regional UFLS programs. The SDT recognizes that Planning Coordinators in a region with a 60 percent capable UFLS program, for example, may have trouble complying with the performance characteristics even under a 25 percent load-generation imbalance scenario. The SDT is not convinced that it would be impossible to comply, but can see that it could be more difficult. Assessments that demonstrate the reliability objective of PRC-006 can be met without meeting the performance characteristics in Requirement R6 (R4 in the revised standard) could be used to support a regional variance.**		
Kansas City Power & Light	No	Do not have a problem with a frequency threshold or duration, however, 58.2Hz and 4 seconds sounds arbitrary. UFLS systems have been in place for years and would be very difficult and expensive to modify to meet the criteria stated here. To justify any need to go to that expense, it is important to establish the engineering basis for this criteria. What is the engineering basis for the 58.2Hz and 4 seconds?
Response: The proposed point was selected to provide 0.2 Hz margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. Based on industry input the SDT has replaced the discrete points in the proposed standard with a continuous curve that provides consistent 0.2 Hz margin between 0 and 60 seconds. The SDT does not anticipate that existing UFLS programs will need to be		

Organization	Yes or No	Question 5 Comments:
redesigned to meet this requirement for load-generation imbalances up to 25 percent. However, the group of Planning Coordinators in a region could pursue a variance if their existing UFLS program does not meet the requirement.		
FirstEnergy Corp	No	The requirement does not exactly match those in PRC-024-1 (Attachment 1) on generator frequency characteristics. In fact, reliability would be better served if the frequency requirements for generators was in PRC-006 rather than PRC-024. For UFLS to be effective, it is a fundamental concept that generation stay connected long enough for load shedding to fully occur. By separating these requirements into different standards, it discounts the need to balance load and generation in a stressed system. PRC-024 allows GO's to be granted exceptions to meeting a fairly generous frequency characteristic but there are no assurances that an equivalent load is shed to balance these exceptions.
Response: The SDT's intent is to provide margin to minimize the risk of generators tripping prematurely during an underfrequency event. Based on industry comment, the SDT has clarified this requirement by replacing the discrete points in the proposed standard with a continuous curve that provides a consistent 0.2 Hz margin between 0 and 60 seconds. While the SDT recognizes that regional criteria traditionally have included underfrequency load shedding and generator trip limits in a single document, this has the disadvantage of spreading generator requirements across multiple standards. The SDT believes system reliability can be maintained as long as the UFLS performance characteristics and the generator trip limits are coordinated regardless of the standards in which these requirements reside.		
Duke Energy	No	We agree this change better coordinates with PRC-024.If coordination with PRC-024 is the ultimate goal, it seems a simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.) The stair step created by the proposed method greatly reduces the area available above the PRC-024 limit.[SERC UVLS team see chart below]Even with the added requirement, the UFLS curve still does not coordinate with the PRC 024 curve at 59.5 Hz. If the 59.3 Hz proposed by PRC-006 is maintained, then it seems PRC-024 should be approximately 0.1 Hz lower, 59.2 Hz. Otherwise, the upper limit for PRC-006 must be increased to coordinate with the PRC-024 curve (e.g. increase by 0.3 Hz to 59.6 Hz). Similarly, the upper requirement does not coordinate with PRC-024 out in time.
Response: Thank you for your support. The SDT has adopted an approach that provides a constant offset of 0.2 Hz between 0 and 60 seconds.		
Exelon	No	This should be left up to the regions. Load trip set points are left up to the Regions and thus so should generating unit settings. Unit coordination requirements should be part of the PRC standards (PRC-001 and PRC-024). This requirement leaves the responsibilities of attaining this goal ambiguous. It would not be appropriate to base compliance on an entity performing a study on the study outcome.
Response: The SDT agrees that unit coordination requirements should be established in PRC-024 and notes that the proposed UFLS standard does not establish requirements for generator trip settings. The proposed UFLS standard requires the group of Planning Coordinators within a		

Organization	Yes or No	Question 5 Comments:
region to design and establish the requirements for the UFLS program to coordinate with the generator requirements established in PRC-024.		
American Transmission Company	No	Please provide the industry with the technical justification for this performance criteria.We would like to add the statement "Unless generation capability or protection warrants or allows for a lower limit" to the end of Requirement R6.2 and R6.3. In the MRO region, this qualification would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load to achieve reasonable frequency recovery in these islands. In these areas, the shedding this quantity of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generators in these islands are acceptable.
Response: This criterion was selected to provide margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. The SDT does not believe it is necessary to modify the requirement as suggested because the performance characteristics in R6 of the draft PRC-006 standard (R4 in the revised standard) would NOT apply to load-generation imbalances over 25 percent. An UFLS program capable of shedding more than 25 percent of a system's load would only need to comply with the performance characteristics up to a 25 percent load-generation imbalance. Beyond a 25 percent load-generation imbalance, the group of Planning Coordinators within a region would not be subject to these requirements and could devise other performance characteristics that would apply under load-generation imbalance scenarios greater than 25 percent. The SDT did, however, modify the underfrequency performance characteristic noting that some entities may have difficulty recovering frequency within 30 seconds with a 25 percent imbalance. This modification to the performance characteristic still maintains a 0.2 Hz margin with the generator tripping limitations proposed by the Generator Verification STD. **The SDT understands the concern over bigger sub-regional UFLS programs. The SDT recognizes that Planning Coordinators in a region with a 60 percent capable UFLS program, for example, may have trouble complying with the performance characteristics even under a 25 percent load-generation imbalance scenario. The SDT is not convinced that it would be impossible to comply, but can see that it could be more difficult. Assessments that demonstrate the reliability objective of PRC-006 can be met without meeting the performance characteristics in Requirement R6 (R4 in the revised standard) could be used to support a regional variance.**		
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT agrees that the UFLS program should coordinate with the performance requirements of the Generation Verification Project (PRC-024-1). The requirement for not remaining below 58.2 Hz for greater than four seconds appears to be within the No Trip Zone area of the Off Normal Frequency Capability Curve in Attachment 1 of PRC-024-1.
Response: Thank you for your support.		
Northeast Power Coordinating Council	Yes	We believe it is important to remove this apparent miscoordination between the generator tripping requirements in PRC-024 and the UFLS program performance requirements in PRC-006.
Response: Thank you for your support		

Organization	Yes or No	Question 5 Comments:
ERCOT ISO	Yes	ERCOT ISO agrees that the UFLS program should coordinate with the performance requirements of the Generation Verification Project (PRC-024-1). The requirement for not remaining below 58.2 Hz for greater than four seconds appears to be within the No Trip Zone area of the Off Normal Frequency Capability Curve in Attachment 1 of PRC-024-1.
Response: The SDT appreciates your support.		
IRC Standards Review Committee	Yes	We do not have a concern with this requirement if the 0.2 Hz above 58.0 Hz is intended as a margin/buffer to ensure generators do not trip pre-maturely.
Response: The SDT's intent is to provide margin to minimize the risk of generators tripping prematurely during an underfrequency event. The SDT thanks you for your comment.		
Colmac Clarion	Yes	Agree that it is a reasonable setpoint for consistent evaluation/simulation; may not be reasonable as a 'limit' after evaluation is complete.
Response: The proposed point was selected to provide 0.2 Hz margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. Based on industry input the SDT has replaced the discrete points in the proposed standard with a continuous curve that provides consistent 0.2 Hz margin between 0 and 60 seconds.		
Alabama Municipal Electric Authority	Yes	The SDT should consider changing the four seconds to six seconds because of the data scanning requirements of other generator functions such as automatic generation control.
Response: Thank you for your support. The proposed point provides 0.2 Hz margin between the generator tripping curve proposed in PRC-024 and the UFLS performance characteristics. The SDT believes that increasing the time to six seconds would not provide adequate margin to minimize the risk of generators tripping prematurely during an underfrequency event.		
Independent Electricity System Operator	Yes	We do not have a concern with this requirement if the 0.2 Hz above 58.0 Hz is intended as a margin/buffer to ensure generators do not trip pre-maturely. However, we do have a concern with R6.3.During the 2003 blackout, the overfrequency limits in R6.3 were violated without any reported adverse effects on the BES. Why are the overfrequency limits needed? If they are not needed to protection equipment, then they should be removed.
Response: Thank you for your comments. The SDT has developed the overfrequency characteristic in Requirement R6.3 to coordinate with the overfrequency trip setting limits proposed in PRC-024. The trip setting limits were developed by the Generator Verification SDT based on the withstand capabilities of generating units. The concern with operation of generating units at off-nominal frequency is the cumulative fatigue effect, so it is possible that generating units experienced significant loss of life on August 14, 2003 even if the adverse effects were not readily		

Organization	Yes or No	Question 5 Comments:
observable immediately after this event.		
Xcel Energy	Yes	We support the philosophy that load shedding should occur prior to generation tripping. We feel it is important to keep these two projects coordinated.
Response: Thank you for your support.		
Hydro-Québec TransEnergie (HQT)	Yes	HQT believe it is important to remove this apparent miscoordination between the generator tripping requirements in PRC-024 and the UFLS program performance requirements in PRC-006.See also our answer to Q8 in regards to frequency treshold.
Response: Thank you for your support. Please see also our response to your comment on Question 8.		
Hydro-Québec TransEnergie (HQT)	Yes	HQT believe it is important to remove this apparent miscoordination between the generator tripping requirements in PRC-024 and the UFLS program performance requirements in PRC-006.See also our answer to Q8 in regards to frequency treshold.
Response: Thank you for your support. Please see also our response to your comment on Question 8.		
PacifiCorp	Yes	Coordination with PRC-024 is very important. PacifiCorp supports this change.
Response: Thank you for your support.		
Ameren	Yes	It is a step in the right direction but additional modifications to the performance characteristics are needed to coordinate effectively with PRC-024. When viewing the frequency and time limits in PRC-024 simultaneously with this draft standard in a graphical manner, there are regions of frequency and time duration for which it is permitted for the generators to operate, but for which it is not permitted for the system as a whole to operate.
Response: The SDT intent is to provide margin to minimize the risk of generators tripping prematurely during an underfrequency event. Based on industry comments, the SDT has clarified this requirement by replacing the discrete points in the proposed standard with a continuous curve that provides a consistent 0.2 Hz margin between 0 and 60 seconds.		
Southern Company		We agree this change better coordinates with PRC-024.If coordination with PRC-024 is the ultimate goal, it seems a simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.).

Organization	Yes or No	Question 5 Comments:
Response: Thank you for your support. The SDT has adopted an approach that provides a constant offset of 0.2 Hz between 0 and 60 seconds.		
SERC UFLS Standards Drafting Team		We agree this change better coordinates with PRC-024.If coordination with PRC-024 is the ultimate goal, it seems a simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.)
Response: Thank you for your support. The SDT has adopted an approach that provides a constant offset of 0.2 Hz between 0 and 60 seconds.		
ReliabilityFirst Corporation	Yes	
System Protection & Control	Yes	
ReliabilityFirst	Yes	
AEP	Yes	
Ontario Power Generation	Yes	
We Energies	Yes	
NextEra Energy Resources, LLC	Yes	
Luminant Power	Yes	
City of Bedford	Yes	
US Army Corps of Engineers	Yes	
Central Lincoln	Yes	

Organization	Yes or No	Question 5 Comments:
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
City of Bedford	Yes	
US Army Corps of Engineers	Yes	
Central Lincoln	Yes	
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
Pepco Holdings, Inc – Affiliates	Yes	
Bonneville Power Administration	Yes	
Electric Market Policy	Yes	
FRCC Standards & Operations Departments	Yes	
Florida Municipal Power Agency and	Yes	

Organization	Yes or No	Question 5 Comments:
Select Members		
Cowlitz County PUD	Yes	

6. **In the first posting, the Characteristics of UFLS Regional Reliability Standards required that UFLS programs be designed to limit the potential for overexcitation (V/Hz) of power system equipment at all Bulk Electric System buses. Based on industry comments, the SDT has revised this requirement in the proposed continent-wide standard to apply only at generator buses and generator step-up transformer high-side buses associated with individual generating units greater than 20 MVA (gross nameplate rating) and generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) that are directly connected to the BES. The SDT believes this change better addresses the need to have UFLS programs designed to coordinate with protection that may trip generators during an underfrequency event. Do you agree with this change?**

Summary Consideration:

The SDT has considered industry input regarding the V/Hz performance characteristic. The majority of comments from the industry supported the changes made to this requirement in the second posting.

However, the team identified the need to make two clarifying changes to the requirement. Based on its own review of the requirement the SDT decided to remove any ambiguity as to whether modeling is required when all or only one threshold is met by combining R 6.4.1 and R6.4.2 with “OR” (now Part 3.3.1 of R3). Based on a comment the SDT also added a third threshold in Part 3.3.1 of R3 to clarify our intent to include wind generation, by adding “Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.” Thus, the applicability is limited to locations at which individual generating units greater than 20 MVA (gross nameplate rating) or generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) are directly connected to the BES or any facility consisting of one or more units that are connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT also has decided to modify Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.

The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from conservative simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard, the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.

Organization	Yes or No	Question 6 Comments:
Northeast Power Coordinating Council	No	We agree with the intent of the change to focus the concern on buses where V/Hz protection may trip generators rather than broadly applying to all BES buses. However, reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage or generating unit/plant nameplate MVA. We recommend that R6.4 apply to all generator buses and generator step-up (GSU) high-side buses similar to R7.1 and R7.2 applying to all generators that trip above 58.0 Hz or below 61.8 Hz.
Response: Thank you for your suggestion. The SDT has considered all industry input and has decided only to make clarifying modifications to the requirement. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity, which the team believes is sufficient accuracy for assessments of UFLS programs. The SDT also has decided to modify Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.		
Midwest ISO Stakeholders Standards Collaborators	No	Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit.This requirement should not be included with this standard because it cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation.The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document. During an under frequency event, generators should be working to pull voltages down anyway.Please see response to question 8 regarding overvoltages related to tripping load without tripping capacitors.
Response: It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT notes that the subject of the cited IEEE and ANSI standards is design and protection of generators and transformers. The proposed Requirement R6.4 (now Part 3.3 of Requirement R3) is a system performance requirement that is coordinated with these standards. If design verification studies demonstrate the potential for generator tripping, corrective measures must be applied to prevent further unnecessary outages or disturbances that would result from tripping the generator. **The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from conservative simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard, the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including**		

Organization	Yes or No	Question 6 Comments:
additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.		
MRO NERC Standards Review Subcommittee	No	Please provide the technical justification for this performance criteria. We are unaware of any UFLS event where V/Hz protection tripped a generator unit.This requirement should not be included with this standard because it cannot be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation.The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document.
Response: It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT notes that the subject of the cited IEEE and ANSI standards is design and protection of generators and transformers. The proposed Requirement R6.4 (now Part 3.3 of Requirement R3) is a system performance requirement that is coordinated with these standards. If design verification studies demonstrate the potential for generator tripping, corrective measures must be applied to prevent further unnecessary outages or disturbances that would result from tripping the generator. **The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard, the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.**		
IRC Standards Review Committee	No	We do not see the need to specify these criteria in the standard. Applicable requirements should be assigned to all generators that meet the compliance registry criteria.
Response: Thank you for your comment. The SDT agrees it would not be necessary to restate these criteria if we were assigning responsibility to the Generator Owners. However, in this case we are defining generator modeling requirements for the Planning Coordinators. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT is specifying these criteria rather than referencing the NERC Statement of Registration Criteria to ensure the technical requirements of this standard are independent of the NERC Statement of Compliance Registry.		
Hydro-Québec TransEnergie (HQT)	No	HQT agree with the intent of the change to focus the concern on buses where V/Hz protection may trip generators rather than broadly applying to all BES buses. However, reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping

Organization	Yes or No	Question 6 Comments:
		in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage or generating unit/plant nameplate MVA. We recommend that R6.4 apply to all generator buses and generator step-up (GSU) high-side buses similar to R7.1 and R7.2 applying to all generators that trip at particular frequency tresholds. See also our answer to Q8 in regards to frequency treshold.
Response: The SDT agrees that the impact of generator tripping on system frequency is independent of the interconnection voltage. However, the SDT believes it is not necessary or practical to assess the potential for tripping of every generator unit. The majority of comments from the industry supported the changes made to this requirement in the second posting. The SDT has considered all industry input and has decided only to make clarifying modifications to the requirement. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT also has decided to modify Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.		
Kansas City Power & Light	No	Do not agree with requirement R6.4 regarding the criteria for ensuring control voltage at the generator does not exceed 1.18 V/Hz for a duration longer than 2 seconds. The operating boundaries and control schemes at the generators are in place for the protection and reliable operation of the generator and should be modeled as they are and UFLS design should be modeled around the generator in the attempt to maintain generator connection to the grid.
Response: Thank you for your comment. The intent of this requirement is as the commenter suggests: to design the UFLS program around the generator in an attempt to maintain generator connection to the grid. However, instead of requiring the Planning Coordinators to model the over-excitation protection of each generator unit and generator step-up transformer the SDT has developed this performance characteristic based on the relevant IEEE standards governing equipment design and protection. The SDT believes this approach achieves the same objective without requiring extensive collection of data and modeling of over-excitation protection.		
NIPSCO	No	Since much of the future generation seems to be wind power- they should be included
Response: The SDT had intended to include wind generators and has modified Requirement R6.4 (now Part 3.3 of Requirement R3) to clarify this intent. **The SDT has modified Part 3.3 to include a reference to "Facilities consisting of one or more units connected to the bulk electric system at a common bus with total generation above 75 MVA gross nameplate rating."**		
Exelon	No	Don't agree with going into the generator over excitation equipment. This is an issue that is regional in nature

Organization	Yes or No	Question 6 Comments:
		and should be addressed at that level.
Response: Thank you for your comment. It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT believes that excitation equipment and generator design and protection is sufficiently uniform across North America that a continent-wide performance requirement is appropriate. **The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage.**		
American Transmission Company	No	Please provide the industry with the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a generator unit.This requirement should not be included with this standard because it cannot be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation.The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000)) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document.
Response: It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT notes that the subject of the cited IEEE and ANSI standards is design and protection of generators and transformers. The proposed Requirement R6.4 (now Part 3.3 of Requirement R3) is a system performance requirement that is coordinated with these standards. If design verification studies demonstrate the potential for generator tripping, corrective measures must be applied to prevent further unnecessary outages or disturbances that would result from tripping the generator. **The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.**		
American Transmission Company	No	Please provide the industry with the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a generator unit.This requirement should not be included with this standard because it cannot be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation.The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic

Organization	Yes or No	Question 6 Comments:
		mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000)) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document.
Response: It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT notes that the subject of the cited IEEE and ANSI standards is design and protection of generators and transformers. The proposed Requirement R6.4 (now Part 3.3 of Requirement R3) is a system performance requirement that is coordinated with these standards. If design verification studies demonstrate the potential for generator tripping, corrective measures must be applied to prevent further unnecessary outages or disturbances that would result from tripping the generator. **The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.**		
FirstEnergy Corp	No	The requirement has been devised to protect generators and step-up transformers from over-excitation based on traditional protection guidelines. However, other elements in the BES can also become over-excited. Dynamic simulations look at many quantities such as voltage and frequency but Volts/Frequency is not a common output that is reviewed. It is suggested that it would be better to require that bulk capacitors be tripped if system voltage exceeds equipment limits.
Response: The SDT initially considered a requirement to trip capacitors when voltage exceeds equipment limits. However, in developing the requirement the SDT realized that the concern with high voltage during an underfrequency event is the potential for generating units to trip by overexcitation protection, potentially exacerbating the underfrequency condition and leading to a blackout. As such, the SDT believes it is important to focus on the reliability impact on the BES and not how the impact should be addressed such as tripping bulk capacitors. While the SDT agrees that V/Hz is not an output quantity commonly reviewed, the capability does exist to monitor this quantity.		
Independent Electricity System Operator	No	The 20 MVA/unit and 75 MVA per generating plant/facility thresholds are the same as those presented in PRC-024, on which we expressed a disagreement. In an islanded situation, each generator's status is critical to ensuring frequency decline is successfully arrested based on the assumption that all on-line generators would not trip within specific frequency bounds unless prior approval has been sought and granted to allow tripping. Not limiting the potential for overexcitation (V/Hz) at the smaller generators/plants exposes the island to a great uncertainty on the amount of generation that can be relied upon to arrest frequency excursion.
Response: The SDT believes it is not necessary or practical to assess the potential for tripping of every generator unit. The majority of comments from the industry supported the changes made to this requirement in the second posting. However, the team identified the need to make two		

Organization	Yes or No	Question 6 Comments:
clarifying changes to the requirement. Based on its own review of the requirement the SDT decided to remove any ambiguity as to whether modeling is required when all or only one threshold is met by combining R 6.4.1 and R6.4.2 with "OR" (now Part 3.3.1 of R3). Based on a comment the SDT also added a third threshold in Part 3.3.1 of R3 to clarify our intent to include wind generation, by adding "Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating." Thus, the applicability is limited to locations at which individual generating units greater than 20 MVA (gross nameplate rating) or generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) are directly connected to the BES or any facility consisting of one or more units that are connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT also has decided to modify Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.		
Xcel Energy	No	No. Criteria in 6.4.1 and 6.4.2 looks like it is only measuring generators that are required to be registered. Yet, with increasing penetration of small generators (<20MVA, <75 MVA aggregate), we feel the scope is not large enough to consider a material impact on the BES by an aggregate of these small generators. (Same concern carries into R7)
Response: The majority of comments from the industry supported the changes made to this requirement in the second posting. However, the team identified the need to make two clarifying changes to the requirement. Based on its own review of the requirement the SDT decided to remove any ambiguity as to whether modeling is required when all or only one threshold is met by combining R 6.4.1 and R6.4.2 with "OR" (now Part 3.3.1 of R3). Based on a comment the SDT also added a third threshold in Part 3.3.1 of R3 to clarify our intent to include wind generation, by adding "Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating." Thus, the applicability is limited to locations at which individual generating units greater than 20 MVA (gross nameplate rating) or generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) are directly connected to the BES or any facility consisting of one or more units that are connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity. The SDT believes that reliability of the UFLS program is supported by assessing the potential for this amount of generation to trip during events involving off-nominal frequency and voltage. The SDT also has decided to modify Requirements R7.1 and R7.2 (now Parts 4.1 through 4.6 of Requirement R4) to apply to the same generating units and plants.		
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes this change creates a clear definition for equipment at generator buses and step-up transformer high-side buses for which the standard applies. However, the NERC UFLS SDT may want to consider adapting the definition of applicable generating units to conform to NERC's Compliance Registry Criteria (NERC Statement Compliance Registry Criteria Rev 5.0 (October 16, 2008) www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0[1].pdf for Generator Owner/Operator:- Individual generating unit greater than 20 MVA (gross nameplate rating) and is directly connected to the bulk power system;- Generating plant/facility greater than 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power

Organization	Yes or No	Question 6 Comments:
		system at a common bus with total generation above 75 MVA gross nameplate rating.This change would bring consistency to the definition of applicable generating units and would ensure that there is no confusion for wind farms and other generating plants/facilities.
Response: Thank you for your suggestion. The SDT has modified Requirement 6.4 (now Part 3.3 of Requirement R3) to include a reference to "Facilities consisting of one or more units connected to the bulk electric system at a common bus with total generation above 75 MVA gross nameplate rating."		
Colmac Clarion	Yes	Be aware that some small generators (>20 MVA but <75 MVA with 'extended' tielines may have difficulty meeting this requirement with some 'older' voltage regulators and stepup transformer arrangements.
Response: The SDT notes that this requirement is not applicable to Generator Owners. The requirement is applicable to Planning Coordinators to ensure that the UFLS program design within each region considers the potential for UFLS program operation to result in high voltage/low frequency conditions that may result in flux beyond design limits of generators and generator step-up transformers. This requirement ensures these impacts are considered during UFLS program design to minimize the likelihood that generation will trip by overexcitation protection which would exacerbate the underfrequency condition, potentially preventing recovery and stabilization of system frequency leading to a blackout.		
Alabama Municipal Electric Authority	Yes	The SDT should consider the potential discrepancy with the generator side and their desire to include automatic load reduction. I assume automatic load reduction would not take place at a generator bus.
Response: The SDT agrees with the commenter's assumption that automatic load reduction would not necessarily take place at a generator bus although this is not precluded by the standard.		
SPP System Protection and Control Working Group	Yes	Please confirm whether this requirement is applicable for generating stations/ plants connected to BES above 100 kV.
Response: This was the intent of the requirement in the second posting. The majority of comments from the industry supported the changes made to this requirement in the second posting. The SDT has decided only to make clarifying modifications to the requirement.		
PacifiCorp	Yes	PacifiCorp concurs with the decision of the SDT drafting team. V/Hz capability is generally associated with generating plants, not all buses within a system.
Response: Thank you for your support.		

Organization	Yes or No	Question 6 Comments:
Luminant Power	Yes	Luminant agrees with the direction of the UFLS SDT. Luminant further requests that the drafting team modify Requirement R6.4 to clarify that the per unit V/Hz limits modeled are 1.18 and 1.10 of Nominal transmission system voltage.
Response: Thank you for your support of the SDT direction on this requirement. However, the SDT has decided not to modify Requirement R3.3 to provide the V/Hz base. The SDT believes it is implicit that the V/Hz base is nominal system voltage divided by nominal system frequency, similar to voltage standards which typically refer to per unit voltage without explicitly stating the voltage base.		
Ameren	Yes	It is an improvement over the previous draft. However, there are still questions as to whether this requirement is needed. Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit. This requirement should not be included with this standard because it cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation.
Response: It is appropriate to include this performance characteristic in this project because overexcitation that occurs as a direct result of UFLS operations must be considered when UFLS programs are designed. The SDT notes that this performance characteristic is based on IEEE and ANSI standards applicable to design and protection of generators and transformers. The proposed Requirement R6.4 (now Part 3.3 of Requirement R3) is a system performance requirement that is coordinated with these standards. If design verification studies demonstrate the potential for generator tripping, corrective measures must be applied to prevent further unnecessary outages or disturbances that would result from tripping the generator. **The SDT acknowledges excitation models do not include V/Hz limiters; however, we also believe that meaningful results can be obtained from simulations without the V/Hz limiter. If the simulated system response exceeds the V/Hz performance characteristics in the standard the group of Planning Coordinators would have the option of developing corrective actions as part of the UFLS program design or including additional modeling for generator units to demonstrate that the V/Hz limiter would prevent the overexcitation condition.**		
ERCOT ISO	Yes	ERCOT ISO agrees with the change.
Response: Thank you for your support.		
Southern Company	Yes	No additional comment.
Pepco Holdings, Inc – Affiliates	Yes	
Bonneville Power	Yes	

Organization	Yes or No	Question 6 Comments:
Administration		
Electric Market Policy	Yes	
SERC UFLS Standards Drafting Team	Yes	
FRCC Standards & Operations Departments	Yes	
Florida Municipal Power Agency and Select Members	Yes	
Cowlitz County PUD	Yes	
City of Bedford	Yes	
US Army Corps of Engineers	Yes	
Central Lincoln	Yes	
Long island power Authority	Yes	
ReliabilityFirst Corporation	Yes	
System Protection & Control	Yes	
ReliabilityFirst	Yes	
AEP	Yes	

Organization	Yes or No	Question 6 Comments:
Ontario Power Generation	Yes	
We Energies	Yes	
NextEra Energy Resources, LLC		No comment.

7. If you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict in the comments section.

Summary Consideration: Most commenters did not feel that there were any conflicts involving the proposed standard. One commenter raised concerns with historic arrangements relative to tie-line standards, and another commenter raised a concern relative to potential timing inconsistency with Automatic Generation Control (AGC). The SDT does not believe either of these issues would impact the frequency response following a major disturbance that results in activation of a UFLS program. However, the SDT believes that to the extent that such existing arrangements are contrary to the reliability objective of the proposed standard, the Planning Coordinators should model any such contract requirements in their UFLS assessments.

Organization	Question 7 Comments:
TRE UFLS Standard Drafting Team	At this time, the TRE UFLS SDT does not believe this proposed standard conflicts with any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or other applicable standard of which the team members are aware.
Response: Thank you for your input.	
Colmac Clarion	Requirement differ from some current contract requirements that were 'inclusive' of existing tieline standards when written.
Response: The SDT is not aware of how existing tie-line standards would impact the frequency response following a major disturbance that results in activation of a UFLS program. Regardless, the SDT believes that grandfathering of existing arrangements that are contrary to the reliability objective of the proposed standard is unwise and may prove to be a hindrance to the successful implementation of this standard. The Planning Coordinators should model any such contract requirements in their UFLS assessments.	
Alabama Municipal Electric Authority	The SDT should re-look at the timing requirements (4 seconds)in this standard and the timing requirements (such as 6 seconds in the AGC requirement) of other standards.
Response: The SDT appreciates notification of the potential conflict. However, Automatic Generation Control (AGC) is not expected to provide a significant contribution to meeting the frequency recovery performance characteristic in the proposed standard. The performance characteristics in the proposed standard reflect the combined system response resulting from activation of the UFLS program as well as the frequency response of load and generation. As such, the SDT believes there is no conflict in establishing requirements for frequency recovery in a time frame before AGC will be activated.	
Xcel Energy	Not aware of any conflicts at this time.

Organization	Question 7 Comments:
Response: Thank you for your input.	
Southern Company	No Comments for Question #7.
ERCOT ISO	No comment
Electric Market Policy	None
Kansas City Power & Light	Not aware of any conflicts.
IRC Standards Review Comittee	None
Public Service Electric and Gas Company	Not aware of any conflicts.
SPP System Protection and Control Working Group	None at this time.
Exelon	Not aware of any conflicts at this time.
We Energies	We are not aware of any conflicts.
PacifiCorp	No comment
NextEra Energy Resources, LLC	No comment.
Luminant Power	None
Ameren	No
FirstEnergy Corp	We are not aware of any conflicts.
Independent Electricity System Operator	None

8. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard PRC-006-1.

Summary Consideration:

Comments on this question covered a wide range of topics. Several comments reiterated concerns stated in response to previous questions while some new concerns were raised.

Several commenters raised concern regarding assignment of applicability for developing the UFLS programs to the Planning Coordinators. Concerns included whether the Planning Coordinators are the correct entity (e.g. as opposed to the Balancing Authority), whether compliance could be assessed against a group of Planning Coordinators as opposed to individual entities, and whether the Planning Coordinators should be required to involve other entities or follow their respective regional standard development processes.

- The SDT reaffirms that the Planning Coordinator is the Functional Model entity with the wide-area view and technical skills required to design automatic UFLS programs and perform the UFLS assessments and noted that the Balancing Authority cannot take action in the time frame required to arrest frequency decline and recovery frequency to 59.3 Hz.
- The SDT has removed the group concept and requirements are now assigned to individual Planning Coordinators.
- The SDT noted that while the standard does not require that the Planning Coordinators involve other entities, the Planning Coordinator must work closely with other entities in performance of its role. The SDT has not included a requirement to involve the Distribution Providers and the Transmission Owners in the process because it would be difficult to measure “involvement” and because this involvement is not required to fulfill the reliability objective of the proposed standard. The SDT also notes that the standard should not be prescriptive as to the processes Planning Coordinators should use in designing UFLS programs. A regional standard that involves other entities in the UFLS program design may be considered.

Several commenters requested that the standard include specific requirements on how the UFLS programs should be designed and implemented, such as the amount of load to be shed, frequency thresholds, time delays, and how the UFLS programs will account for the impact of generators that trip above the underfrequency trip curve proposed in PRC-024.

- The SDT replied to these comments by noting that the proposed standard is focused on what reliability goals must be met. The proposed standard allows Planning Coordinators to decide on UFLS design parameters to meet these requirements. The SDT also noted that due to differences in physical system characteristics between regions, the design of the UFLS programs is best left to the Planning Coordinators in each region. Comments received during the two postings indicate industry support for this approach.

Several commenters requested justification for the performance requirements included in the standard.

- The SDT replied that the technical justification for these performance characteristics is to ensure that generation does not trip before the UFLS program has time to operate to arrest frequency decline and recover frequency within acceptable limits. The characteristics in the proposed standard have been coordinated with the trip limitations proposed by the Generator Verification SDT in PRC-024 and with equipment design and protection guides in IEEE standards.

Several commenters requested that the SDT address issues such as requiring generator owners to provide their relay setting data, minimum requirements on generator governing response, limitations on generator tripping for off-nominal frequency, maintenance and testing of UFLS relays.

- While the SDT agreed that many of the concerns raised by commenters are valid, they also are outside the scope of the SAR for this project. Where applicable, the SDT noted existing STDs that are addressing these issues. Specifically, the Generator Verification STD (Project 2007-09) is establishing limitations on generator tripping for off-nominal frequency and requirements for generators to report non-conforming protection settings in PRC-024, and the Protection System Maintenance & Testing SDT (Project 2007-17) is addressing maintenance and testing for all relay types in PRC-005.

Several commenters raised concerns and provided recommendations on requirements involving procedures for coordination with other regions and criteria for selecting islands.

- In response to a variety of comments the SDT deleted requirement R4 and combined other requirements to simplify the requirements for inter-area coordination and criteria for selecting islands to be used as a basis for designing a UFLS program. These revised requirements are contained in Requirements R2 for selecting islands and R5 for inter-area coordination.

Several entities recommended that the proposed standard exclude small entities from requirements to implement the UFLS program designed by the group of Planning Coordinators in their region.

- The SDT indicated this is an aspect of the UFLS program design assigned to the group of Planning Coordinators. The SDT further noted that the group of Planning Coordinators can provide in the UFLS program such allowances as long as compliance with the performance characteristics in requirement R3 (requirement R6 in previous posting) is achieved.

One entity identified potential conflicts between approved reliability standard EOP-003, Load Shedding Plans, and the proposed standard.

The SDT agrees that PRC-006-1 and EOP-003-1 should not include duplicative or contradictory requirements. The SDT has requested and received Standards Committee approval to propose a supplement to its scope to include making conforming changes to EOP-003-1. The Supplemental SAR and proposed revisions to EOP-003-1 have been included with the third posting of PRC-006-1. One entity indicated that the requirement for post-event analysis presently contained in PRC-009 has not been included in the proposed standard, leaving a gap in analysis of events. The entity suggested this must be covered in a reliability standard and should not be referred to ERO Rules of Procedure.

- Upon further consideration, the SDT agreed with the comment and added a requirement to include an assessment of the performance of UFLS equipment and the UFLS program effectiveness (new Requirement R11) within one year of an actuation of UFLS resulting in a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program.

Several commenters requested that the database should include all data required to perform a UFLS Assessment.

- The SDT notes that the database is intended to document the load tripping implemented by Distribution Providers and Transmission Owners to meet Requirement R9. In fulfilling the Planning Coordinator function, the groups of Planning Coordinators have the ability to obtain protection settings they need to model to comply with R4 and R11. Planning Coordinators and Transmission Planners routinely obtain similar data to perform planning studies required by the Transmission Planning (TPL) standards.

Several entities requested that the drafting team propose definitions for several terms to be included in the NERC Glossary, including the terms region, island, underfrequency load shedding (UFLS), and annually.

- The SDT provided explanations of how these terms are used in the proposed standard, and noted that the terms region, island, and UFLS are understood terms used within the industry and the word annually is used as defined in a collegiate dictionary. The team did; however, clarified in the standard that “region” refers to a Regional Entity footprint.

Organization	Question 8 Comments:
TRE UFLS Standard Drafting Team	The TRE UFLS SDT appreciates the opportunity to provide these comments and commends the NERC UFLS SDT for its efforts.
Response: Thank you for your support.	
Bonneville Power Administration	The Applicability should be Planning Coordinators and Balancing Authorities. BPA suggests that everywhere it currently states Planning Coordinator that it be changed to ?Planning Coordinator/Balancing Authority?. **Response: The SDT believes the Planning Coordinator is the Functional Model entity with the wide-area view and technical skills required to design UFLS programs and perform the UFLS assessments. The Balancing Authority cannot take action in the time frame required to arrest frequency decline and recover frequency to 59.3 Hz within 60 seconds.** R3. - This needs to say why they are selecting portions of the BES that may form islands. The reason would be "that may form islands to simulate frequency performance and design the UFLS schemes." **Response: The reason is given in R5 (now R2), “Each group of Planning Coordinators shall identify an island(s) as a**

Organization	Question 8 Comments:
	basis for designing a UFLS program." R5. Second bullet - This should include both "relay scheme or special protection system." **Response: The SDT agrees with this comment and has revised the requirement (now R2, Part 2.2) accordingly.** Related to R9. - Each Generator Owner also needs to provide data for their under frequency trip settings, if they are within the band specified, 58.0 Hz to 61.8 Hz, since they also need to be considered in the simulations. **Response: Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. Adding such a requirement in PRC-006-1 will create a redundant data requirement already contained in PRC-024-1.**
Northeast Power Coordinating Council	NPCC has previously commented that the objective to control frequency overshoot cannot be met through UFLS program design alone in the absence of adequate generating unit governing response. Our immediate concern has been addressed by increasing the maximum overshoot limit to 61.8 Hz and we support this modification to the performance requirements. However, we expect this concern will resurface if standards requiring minimum frequency response are not implemented and further declines in system frequency response are observed. NPCC recommends that NERC develop standards for unit governing response that are consistent with and support the reliability objectives of standards PRC-006 (UFLS) and PRC-024 (Generator Performance). **Response: The SDT agrees, though this is outside the scope of its activities. We suggest you submit this suggestion using a *Standards Suggestions and Comments Form* – the form can be downloaded from the Standards Resources Web Page, or using the following link:** **http://www.nerc.com/files/Standards_Input_Form_Final_2008June30.doc** NPCC also notes that it may not be possible for the Planning Coordinators to design a reliable UFLS program that will arrest and recover declining frequency if an excessive number of generators are exempted from meeting the underfrequency performance requirements in PRC-024. **Response: The SDT agrees, though this needs to be addressed by the Project 2007-09 (Generator Verification) PRC-024 SDT.** Hydro-Quebec TransEnergie has technical parameters that differ from those specified in Requirements R6 and R7. A Variance will be needed to address those specific concerns. **Response: A variance for the Québec Interconnection is included in the third posting of the standard.**
Southern Company	--- R8: It is problematic for a loosely organized group of Planning Coordinators to create and maintain a database. There are

Organization	Question 8 Comments:
	several practical and compliance issues with this. This should be assigned to an entity with clear responsibilities and pro
Response: This requirement (now R6) has been reassigned to individual Planning Coordinators. Annual collection of data is desirable in case events need to be analyzed. A database can be any collection or compilation of data the Planning Coordinator chooses.	
ERCOT ISO	Comment 1- May need to consider defining the meaning of region (Region) in the NERC Glossary so it is clear for the responsible entities for this standard. **Response: The SDT intended "region" to relate to the traditional sense of the defined boundaries of a Regional Reliability Organization (RRO) and its successor the Regional Entity. The SDT feels that the concept of a "region" is generally understood throughout the industry and does not believe that a unique definition is required. The term "Regional Entity footprint" replaces "region" in the third draft.** Comment 2 Will it be necessary for ERCOT ISO to have a procedure for coordinating with groups of Planning Coordinators, since we are essentially a group of one? Maybe language could be added to the standard to clarify for this situation. **Response: The SDT modified the standard to no longer require a procedure. The requirements are also now assigned to individual Planning Coordinators rather than groups.**Comment 3 - It would be appropriate for the load referenced in the imbalance calculation in requirement R6 to include system (island) losses. The standard should be clearer. **Response: The SDT intentionally excluded island losses from the imbalance definition. The losses within an island are difficult to measure because the losses in the steady-state pre-event condition will change upon formation of the island. The SDT notes that excluding losses results in a slightly more conservative assessment because more generation would have to be online for a given imbalance if losses are included in the equation. In most cases the losses are on the order of 1 to 3 percent; thus while excluding losses is conservative, it is not overly conservative.**
Midwest ISO Stakeholders Standards Collaborators	R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria. **Response: The SDT recognizes the difficulties that could be encountered in identifying islands. Nevertheless, there may be portions of a system that obviously have a higher likelihood of islanding as compared to others. How extensive an analysis to identify islands needs to be is a judgment that cannot be written into a standard and must be left to the discretion of the Planning Coordinators involved. The standard only requires that criteria for identifying islands be developed, documented and applied.** R2 We would suggest removing the word "consistent" because the program can not be applied consistently across the MRO

Organization	Question 8 Comments:
	Region. The Canadian systems need to shed more load than the US portion of MRO. We need to focus on coordination issues between geographic areas, not on consistent application across a NERC region. Perhaps what was intended is to state that load shedding should be applied uniformily across any island footprint. **Response: The SDT agrees with the comment and has revised requirement R3 (that reflects merging of Requirement R2 into R5) with removal of the word, "consistent."** R4 - Revise text so that the "agreement" between all entities is well documented through several examples: meeting minutes, a formal agreement to work together, results of common drills, examples of coordination of UFLS models, etc.) We would propose that the assessment for non compliance would be located in the formal agreement to work together since all parties should understand the risk or consequences of the group effort. **Response: Requirement R4 has been deleted.** These standards do not appear to consider or address if capacitors should be automatically tripped during UFLS to avoid overvoltage conditions. Do other standards address this or does this draft standard need to be modified? **Response: The SDT feels that R6.4 (Part 3.3 of requirement R3 in the third draft) appropriately addresses overvoltage conditions without specifying how the volts per hertz requirement should be met. The SDT believes that requiring capacitor tripping in the standard would address "how" to meet the requirement rather than stating "what" reliability objective is being addressed.**
SERC UFLS Standards Drafting Team	R8: It is problematic for a loosely organized group of Planning Coordinators to create and maintain a database. There are several practical and compliance issues with this. This should be assigned to an entity with clear responsibilities and processes to accomplish the task. Additionally, annually and database is unnecessarily restrictive given the study is only required on a 5 year basis and in light of existing data collection processes. Recommend revision R8 as follows: shall compile/assemble information provided by their Transmission Owners and Distribution Providers for use in UFLS assessments and event analyses. Databases should add value and not create extra work that does not directly contribute to the completion of the study.--- **Response: This requirement (now R6) has been reassigned to individual Planning Coordinators. Annual collection of data is desirable in case events need to be analyzed. A database can be any collection or compilation of data the Planning Coordinator chooses.** R7.1 and 7.2 could have the effect of shifting the generators burden of staying on line to the load customer who must be shed to account for the generators less-than-expected frequency performance. The generators must be modeled because that is the way they perform, but an exception for frequency support must be difficult for a generator to obtain.--- **Response: The SDT agrees, though, exceptions for frequency support provided by the generators need to be addressed by the Project 2007-09 (Generator Verification) PRC-024 SDT. The current draft of PRC-024 does require documentation and response to technical review by other entities for any non-conforming trip settings.**

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	R10 should say ?shall implement the UFLS program rather than shall provide load tripping in accordance with the UFLS program because the phrase ?provide load tripping could be confusing.--- **Response: The SDT deliberated on the words "shall implement" and while we agree with the intent we feel that "shall provide load tripping" is more explicit.** R1 through R8: The concept of PC's joining a group to design a UFLS scheme is flawed. Compliance should never be assessed on a group basis. Each PC (or TP) must be allowed to demonstrate compliance to the standard independently so compliant PCs/TPs are not penalized along with the non-compliant one(s). The standard should be applicable to individual PC's/TPs to design their UFLS scheme to meet the other requirements. The performance characteristics insure that the schemes from different PC's/TPs will coordinate. However, if a group approach is mandated, then sub-regional groups must be allowed in lieu of regional groups.--- **Response: Thank you for your comment. The group of Planning Coordinators concept has been removed and replaced by individual Planning Coordinators.** R4 is an unnecessary complication, and should be deleted. A procedure for identifying islands between Regions is not necessary. What if there are no credible islands between Regions? R5 ensures that when credible islands between Regions are identified that all affected entities jointly study UFLS scheme effectiveness within the island.--- **Response: The SDT agrees and Requirement R4 has been deleted.** R6: Does this requirement say that performance requirements must be met only at a 25% imbalance? Or is it requiring performance requirements to be met at lower imbalances too? If yes, we recommend performing both a 25% and a 15% imbalance test to add clarification.--- **Response: The requirement indicates that the performance characteristics apply to any percentage between 0 and 25. A number of imbalances need to be simulated to demonstrate that the performance characteristics can be met through the range**. R10: Does each DP have to specifically meet the UFLS scheme? For example, if the UFLS scheme is for 30% load in 3 steps of 10% each, some small DP's may not be able to achieve that fine a resolution. Some allowance should be made for aggregating DP's to meet the overall scheme. This allowance should be achieved by making the TO responsible for implementing the UFLS scheme. The TO has a wider area of control and responsibility and is therefore in a better position to coordinate the implementation.--- **Response: The group of Planning Coordinators can provide in the UFLS program any such allowance as long as compliance with the performance characteristics in requirement R3 (requirement R6 in previous posting) is achieved.** Unless there is a high bar in PRC-024 to obtain an exception, this passes the responsibility for generators to support frequency on to the loads (to support frequency by shedding). To compensate this standard needs a requirement for generators which do

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	not coordinate with the R6 requirements to arrange for load to be shed to make up for their generator tripping.--- **Response: Per R5 of the first draft of PRC-024-01, Generator Owners will need to document, subject to peer review, any generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1. Since this standard does not apply to Generator Owners, the preceding comment should be directed to Project 2007-09 which covers PRC-024-01.** **The proposed standard allows Planning Coordinators in each region to determine what measures will be included in the program design to account for the impact of generators with trip settings that trip above the curve in PRC-024.** R7.1: This should not require the modeling trip settings of all generators that trip at or above 58.0 Hz. Since most generators have trip settings for reduced frequency that holds for long periods (e.g. 30 minutes), this would require modeling trip settings of almost all generators. It should only require the modeling trip settings of generators that would trip within the performance envelope defined by R6.1 and R6.2.--- R7.2: This should not require the modeling trip settings of all generators that trip at or below 61.8 Hz. Since most generators have trip settings for higher frequency that holds for long periods (e.g. 30 minutes), this would require modeling trip settings of almost all generators. It should only require the modeling trip settings of generators that would trip within the performance envelope defined by R6.3.--- **Response: The SDT agrees and has modified Parts 4.1 through 4.6 of requirement R4 (previously R7.1 and R7.2) to require the modeling of generators with protection settings above and below the frequency-time curves rather than focusing on tripping above or below a specific frequency threshold.** It is not clear if the standard requires one specific UFLS scheme for the entire Region. One scheme for the Region should not be mandated. Flexibility should be allowed for different schemes within the Region as long as each scheme meets the performance requirements. **Response: The SDT has addressed this concern by eliminating the word "consistent."**
FRCC Standards & Operations Departments	We appreciate the Drafting Teams efforts on this very difficult standard and would offer the following suggested clarifications:R8. Each group of Planning Coordinators shall create and annually maintain a UFLS database containing relay information provided by their Transmission Owners and Distribution Providers for use in UFLS assessments and event analyses. Suggest rewording R8 as follow: R8. Each group of Planning Coordinators shall maintain a UFLS database which identifies the participating Planning Coordinators, contributing entities and contains information (as defined in R9) provided by their Transmission Owners, Distribution Providers and Load Serving Entities for use in UFLS assessments and event analyses. **Response: The SDT has revised Requirement R8 (now R6) in response to a number of different suggestions from commenters. However, the SDT has not included requirements to identify the participating Planning Coordinators or for Load Serving Entities (LSEs) to provide data. This requirement (now R6) has been reassigned to individual Planning Coordinators. The equipment owners (Distribution Providers and Transmission Owners) are the entities with the data**

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	required by Planning Coordinators, so there is no reason to include LSEs in this requirement. Suggest adding Load Serving Entities to R9. **Response: The equipment owners (Distribution Providers and Transmission Owners) are the entities with the data required by Planning Coordinators, so there is no reason to include LSEs in this requirement.** R10. Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates. Suggest rewording R10 as follows: Each Transmission Owner, Distribution Provider and Load Serving Entity shall provide forecast load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates. **Response: The SDT has not added the word "forecast" to the requirement. Because automatic UFLS programs must be planned in advance, the use of forecasted load is considered a given.**
MRO NERC Standards Review Subcommittee	R1 - Reword the requirement to state the Planning Coordinators within a region shall have an agreement with all the Planning Coordinators rather than creating a new group. (For example similar to agreement requirements between BAs in EOP-001, between GOs and transmission entites in NUC-001, and RCs to form an agreement in IRO-001 R7.) Proposed wording for R1: "Planning Coordinators shall have agreements with all Planning Coordinators in the region, that shall, at a minimum, contain provisions for cover fulfillment of the subsequent UFLS requirements in the standard."This agreement would clarify how "group" responsibilites for compliance and penalties would be assigned to its member entities. For example, would all Planning Coordinators be non-compliant, if one or more members of the group is non-compliant or if a group could not come to consensus on elements needed to fullfill a requirement? Would the financial penalty be shared among the group or would each member be assessed separate penalties? **Response: The group of Planning Coordinators concept has been removed and replaced with individual Planning Coordinator applicability.** R2 We suggest the following revised wording, "shall design a load shedding program or multiple load shedding programs so that all areas of the region are covered." In the MRO, the Canadian portions of the system need to shed more load than the U.S. portion of the system. There needs to be coordination within each potential island, but not necessarily consistent across each, entire NERC region. Perhaps what was intended is to state that load shedding should be applied uniformly across an island footprint. **Response: The SDT has addressed this concern by eliminating the word "consistent."** R4 - Revise text so that the "agreement" between all entities is well documented through several examples: meeting minutes, a formal agreement to work together, results of common drills, examples of coordination of UFLS models, etc.) We would propose that the assessment for non-compliance would be located in the formal agreement to work together since all parties should understand the risk or consequences of the group effort.

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	Response: Requirement R4 has been removed. R6.1 To match the design emphasis that is included in R6.2 and R6.3, we suggest . . . no less that 58.0 Hz per simulated event. **Response: The SDT has revised these requirements to refer to frequency-time curves rather than specific thresholds and time durations. The SDT believes that the revised requirements (now Parts 4.1 and 4.2 of R4) address the commenters' concern.** R8 - Since the interpretation of "annually" can vary widely, we suggest this rewording, "each calendar year and within 15 months of the last update". **Response: Since "annually" is not defined a NERC term, it has the meaning "occurring or happening every year or once a year." as found in a collegiate dictionary. The SDT believes the reliability objective of this requirement is met without specifying details of when during the year the requirement is fulfilled.** R9 If the inclusion of Transmission Owner is determined to be redundant, reword to, Each Distribution Provider shall provide. . ., as noted in response to Q1.b. **Response: The SDT has decided to retain both the Distribution Provider and the Transmission Owner in the applicability for this requirement. The drafting team provided the rationale for keeping Transmission Owner in response to comments to Question 1B.** R10 If the inclusion of Transmission Owner is determined to be redundant, reword to, Each Distribution Provider shall provide . . ., as noted in repsonse to Q1.b. **Response: The SDT has decided to retain both the Distribution Provider and the Transmission Owner in the applicability for this requirement. The drafting team provided the rationale for keeping Transmission Owner in response to comments to Question 1B.** add R11 - Since reactive power device overvoltage or underfrequency protection may be included to the UFLS program assessment, we suggest adding the Requirement, "R11. Each Distribution Provider and Transmission Owner shall provide its reactive power device overvoltage or underfrequency protection information in the format and according to the schedule specified by the applicable Planning Coordinator." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section.] **Response: The database is intended to document the load tripping implemented by Distribution Providers and Transmission Owners to meet Requirement R9. In fulfilling the Planning Coordinator function, Planning Coordinators have the ability to obtain protection settings they need to model to comply with R4 and R11. Planning Coordinators and Transmission Planners routinely obtain similar data to perform planning studies required by the Transmission Planning (TPL) standards.** add R12 - Since reactive power device overvoltage or underfrequency protection should be included in the UFLS program design

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	for a specific island, we suggest adding the Requirement, "R12. Each Distribution Provider and Transmission Owner shall provide reactive power device tripping in accordance with the UFLS program designed by the applicable Planning Coordinator for each region in which they operate." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section.] **Response: The SDT has added a new requirement R10 that requires Transmission Owners to provide automatic switching of Elements in accordance with the UFLS program design. The SDT believes this general requirement is more appropriate to include both energizing and de-energizing reactive devices or any other system Elements when included by the Planning Coordinators as part of the UFLS program design.** add R13 - Since generator off nominal frequency protection information may be included to the UFLS program assessment, we suggest adding the Requirement, "R13. Each Generator Owner shall provide its off nominal frequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators." **Response: The SDT does not believe this requirement is necessary. Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. Adding such a requirement in PRC-006-1 will create a redundant data requirement already contained in PRC-024-1.** add R14 - Since the coordination of generator off nominal frequency protection should be included to the UFLS program design for a specific island, we suggest adding this Requirement "R14. Each Generator Owner shall have evidence that they provided any coordination that is required by the applicable regional group of Planning Coordinators to meet UFLS program specifications." **Response: The SDT does not believe this requirement is necessary. Coordination between generator off-nominal frequency tripping and UFLS is already being achieved between this standard and draft PRC-024-1.** It is not clear if the standard requires one specific UFLS scheme for the entire Region. One scheme for the Region should not be mandated.Flexibility should be allowed for different schemes within the Region as long as each scheme meets the performance characteristics. **Response: The SDT has addressed this concern by eliminating the word “consistent.”** Below is a list of technical requirements or issues the MRO NSRS would like the UFLS DT to consider for either a reference document or for regional variences. A. Limited Number of Island Loads - What allowance should made for Distribution Providers with a limited number of loads in a designated island? **Response: Planning Coordinators can provide in the UFLS program any such allowance as long as compliance with the performance characteristics in requirement R3 (requirement R6 in previous posting) is achieved.**

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	B. 58 Hz Limit - Consideration should be given to circumstances in some islands where a lower frequency limit would allow better UFLS program performance. For instance the the Canadian example mentioned above. **Response: This may be addressed through a variance as outlined in the NERC Rules of Procedure. The SDT encourages the requestor of a variance to submit its request with a SAR which addresses the variance in detail.** C. Coordination with the Proposed PRC-024 Standard - Consideration should be given for proper coordination for of this standard (UFLS) with the PRC-024 standard especially with reguard to off-nominal frequency settings for generation. **Response: The SDT coordinated with the PRC-024 Generator Verification Standard Drafting Team (GV SDT) by providing the underfrequency performance curve to ensure that the performance characteristics do not conflict with the generator off nominal frequency capability curve. The SDT will continue to coordinate with the GV SDT.** D. Reference Document - We think it would be valuable to develop a companion reference document that may contain the following expectations and intentions: - The intent of this standard is to ensure UFLS programs are effective, and to the extent possible, that potential problems have been addressed in the design phase. - This standard should achieve an appropriate level of reliability and not just the least common denominator. An evaluation should be made to determine if the minimum load shedding requirement is sufficient and appropriate for a given geographic region. Although no geographic region (potential island) is obligated to exceed the minimum load shedding requirement, load shedding beyond the minumum requirement is encouraged when there is an identified advantage of doing so. - Overall coordination issues are easier to satisfy for programs that shed the minimum amount of load. Such programs will be better behaved over the smaller range of overloads, but the system will collapse if loss of generation (or import) exceeds the amount of load shed. Larger, more aggressive load shedding programs will provide a larger safety net at the expense of wider voltage and frequency deviations, and generation in those areas will need to accept more off-nominal frequency exposure to achieve coordination with load shedding. - UFLS analysis has to deal with considerable uncertainty in a multitude of variables. It is assumed that conflicting performance requirements and tradeoffs will be documented and resolved through application of engineering judgment. - This standard acknowledges that performance measures such as frequency and voltage deviation are subjective. Both voltage and frequency are influenced by hard-to-quantify factors that vary in real time, such as load damping, the net governor response, and inertia of spinning on-line units. Such performance measures can only be applied in consistent fashion to a tightly defined set of qualifying assumptions. - This standard acknowledges that UFLS is basically a last ditch effort to prevent system collapse and that it has limits. It is not possible to achieve desired performance for all of the unlikely events that may occur in real life. - Performance characteristics given in this standard should be treated as design targets or design guidelines. Studies run to

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	develop UFLS programs may indicate different design criteria is appropriate as part of the overall compromise that has to be struck between performance and the level of load shedding coverage that is desired. - There is no perfect tool for studying UFLS, and this standard is not meant to prescribe any particular engineering approach to system analysis and review of UFLS performance. For example, the equivalent inertia method allows for sensitivity analysis and broader insight into the frequency decay dynamics. Likewise, the full transient stability case is more useful for simulating actual disturbance conditions including voltage transients. **Response: The SDT agrees with many of the guiding principles described above, but does not agree that a reference document is necessary. The SDT notes that UFLS programs have existed for forty years and believes that the Planning Coordinators have adequate expertise to understand the requirements of the proposed standard.** **The SDT also disagrees that standard requirements should be viewed as design targets or guidelines. The SDT assumes that reasonable assumptions pertaining to load damping and governor response will be made in the UFLS assessments, and that inertia will be representative of the systems studied.** **The SDT notes that a UFLS program capable of shedding more than 25 percent of a system's load would only need to comply with the performance characteristics up to a 25 percent load-generation imbalance. Beyond a 25 percent load-generation imbalance, a UFLS program would not be subject to any NERC imposed requirements, although the Planning Coordinators within a region could devise other performance characteristics that would apply under load-generation imbalance scenarios greater than 25 percent. The SDT understands the concern over larger sub-regional UFLS programs. The SDT recognizes that Planning Coordinators in a region with a 60 percent capable UFLS program, for example, may have trouble complying with the performance characteristics even under a 25 percent load-generation imbalance scenario. The SDT is not convinced that it would be impossible to comply, but can see that it could be more difficult. Assessments that demonstrate the reliability objective of PRC-006 can be met without meeting the performance characteristics in Requirement R6 could be used to support a request for a regional variance.** **While the standard does not prescribe any particular engineering approach to system analysis, the SDT believes that dynamic simulations are the only appropriate means of assessing compliance to the performance characteristics in R3 (previously R6).**
Kansas City Power & Light	1. What is the engineering basis for any of the boundary and threshold criteria established by requirement 6 and its sub-requirements? These prescribed requirements may not fit with already established UFLS systems and to justify the expense of changes there should be a sound engineering basis for doing so.2. **Response: The technical justification for these performance characteristics is to ensure that generation does not trip before the UFLS program has time to operate to arrest frequency decline and recover frequency within acceptable limits. The characteristics in the proposed standard have been coordinated with the trip limitations proposed by the Generator Verification SDT in PRC-024 and with equipment design and protection guides in several IEEE standards. The SDT does not anticipate that existing UFLS programs will need to be redesigned to meet this requirement (now**

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	Requirement R3) for load-generation imbalances up to 25 percent. R9 requires Transmission Owners and Distribution Providers according to a schedule and format specified by the Planning Coordinator, but does not require Generator Owners to provide generator protection information. Recommend the SDT consider the inclusion of generator information in the appropriate places in these requirements. **Response: The SDT does not believe this requirement is necessary. Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. Adding such a requirement in PRC-006-1 will create a redundant data requirement already contained in PRC-024-1.**
IRC Standards Review Comittee	R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria. **Response: The SDT recognizes the difficulties that could be encountered in identifying islands. Nevertheless, there may be portions of a system that obviously have a higher likelihood of islanding as compared to others. How extensive an analysis to identify islands needs to be is a judgment that cannot be written into a standard and must be left to the discretion of the Planning Coordinators involved. The standard only requires that criteria for identifying islands be developed, documented and applied.** The fourth bullet in R5 is unnecessary since (all assets) (assets in Island 1) (assets in island 2) - .. = (remaining assets not in any other island)Alternatively, the SDT may want to consider a requirement to perform one or more ad hoc stress tests that can be used to define islanding conditions. If PC passes the stress test, than there is no obligation to define an island within the PC; if the PC fails the stress test, than the PC must use the results as a partial (or complete) basis for defining one or more PC islands **Response: The SDT believes that Part 2.3 of Requirement R2 (fourth bullet of old requirement R5) is necessary to ensure regional coordination, and that if islands are not identified through system studies, historical events or planned islands, then the region as a whole is studied as an island in the assessment. The SDT notes that Planning Coordinators could include conducting a stress test to define islanding conditions as part of their criteria to identify islands to meet Requirement R1 (old requirement R3).**
Cowlitz County PUD	Past experience has proved from efforts to comply with other data request mandated standards a disconnect on what specific data needs to be on hand for proper modeling. Keep in mind that the DP usually does not have the expertise, including many TOs, on what data will be needed. I would suggest there be a requirement that the PC not only develop the data set required,

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	but actively (not passively) communicate to its DPs and TOs what is required. Simply expecting entities to stumble around in a web site and find the requirements complicates compliance efforts. Please note that I am not an expert in UFLS schemes and offer my limited knowledge as a compliance and distribution engineer. Thank you for the opportunity to join in this venue.
Response: The SDT understands the concern and believes that requiring that the data be provided according to the format and schedule defined by the Planning Coordinators in Requirement R8 establishes the "what" is needed to properly conduct UFLS assessments and events analyses.	
City of Bedford	Distribution providers with fewer than 10,000 meter should be exempted for the UFLS program because their ability to effect the stability of the electrical grid is minimal and the cost of installing and maintaining the system would excessive.
Response: Planning Coordinators can provide in the UFLS program such an allowance as long as compliance with the performance characteristics in requirement R3 (requirement R6 in previous posting) is achieved.	
Alabama Municipal Electric Authority	In requirement 10, "R10. Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates.", it requires the Distribution Provider to provide load tripping. This seems to imply that the Distribution Provider would not be able to satisfy this obligation in aggregate from its Balancing Authority or Transmission Operator through its power supply contracts. The requiement to provide load tripping is especially troublesome for small entities that have only one feeder supplying the load of its end use customers. Additionally a small entity that is registered as a Distribution Provider that has less than 100 MWs of load will provide little help in affecting the frequency of the BES. The SDT should consider a class of Distribution Providers and not all Distribution Providers.
Response: Planning Coordinators can provide in the UFLS program such an allowance as long as compliance with the performance characteristics in requirement R3 (requirement R6 in previous posting) is achieved.	
NIPSCO	Any standard neededs to be very general- should include the effect of load on frequency;Define what amount of load they require to trip; Include rate of frequency change protection.Only require planned load tripping; Actual load is much more difficult to predict on lower voltagecircuits.
Response: The SDT tried to be specific on what needs to be accomplished for reliability without being prescriptive on how to meet what is required. The details of the UFLS program such as amount of load tripping are to be defined by Planning Coordinators.	
SPP System Protection and Control Working Group	None at this time.
Long island power	Consider rewoeding R10 to better limit the Compliance aspect for the DP to implement setting UFLS relays based on the

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Authority	forecasted loads projected for the peak period. Suggest this R10 - The DP once per calendar year shall review the forecasted loads it is serving and provide for UFLS in accordance with the UFLS program designed by the group of planning Coordinators for each region in which it operates.
Response: The SDT has not added the word "forecast" to the Requirement. Because automatic UFLS programs must be planned in advance, the use of forecasted load is considered a given. Details as to whether peak load or other load conditions are used as the basis of the program design is left to Planning Coordinators to determine.	
Exelon	There is a concern with high frequency requirements because they are not clear as to what should occur or how it should be mitigated. If island frequency is greater then 60.7 HZ for more than 30 seconds what type of action needs to occur? What is the technical justification for these levels? **Response: The technical justification for this requirement is to ensure that generation does not trip as a result of frequency overshoot following operation of the UFLS program. The overfrequency characteristic in the proposed standard has been coordinated with the overfrequency trip limitations proposed by the Generator Verification SDT in PRC-024. If island frequency is greater than 60.7 Hz for more than 30 seconds the Planning Coordinator should modify the UFLS program design to reduce the level of overshoot, such as by increasing the number of UFLS stages and decreasing the amount of load shed at each stage.** In the previous Characteristics document the high voltage levels were different than the levels in this draft standard. **Response: The SDT believes the commenter is referring to the overfrequency limits having changed. The SDT raised the limits based on industry input during the first posting. The limits have been raised to take advantage of generator capability while maintaining coordination with the generator trip limits proposed in PRC-024. Based on industry input in the second posting, the overfrequency limits have been modified again to convert the discrete points to a curve.** Due to the inherent difficulty in accurately postulating load and generation islands, establishing frequency limits for such islands is even more difficult. There should be a criteria as to how the studies are done (including islanding criteria and size) if there are going to be bounds placed on the frequency result of the simulation. **Response: The SDT has defined the maximum imbalance between load and generation for which the performance requirements must be achieved. The SDT believes that for imbalances up to 25 percent it is possible to meet the performance characteristics for any island that may form. Details such as the process by which islands are identified are left to Planning Coordinators. The SDT believes that due to differences in physical system characteristics between regions, issues such as how studies are done are best left to the Planning Coordinators in each region. Comments received during the two postings indicate industry support for this approach.** If the timing components (4,10,20 seconds) are removed, then regions should establish minimum generator tripping standards for load shedding. Unit tripping should be a balance between limiting cumulative damage while at the same time coordinating with

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	load shedding levels in order to arrest frequency decline. **Response: The SDT agrees that unit tripping limits should achieve a balance between limiting cumulative damage while at the same time coordinating with load shedding levels in order to arrest frequency decline. This balance is being accomplished on a continent-wide basis by this SDT's coordinating the drafting with the Generator Verification SDT rather than a regional basis as suggested by the commenter.** Disagree with requirement 5. Criteria for island formation and the resulting requirements for mitigation should be included in a standard where affected parties may participate through the open and fair NERC process. There should not be some unspecified criteria left up to various entities with no oversight or standaridized development process. It would be very difficult if not impossible to determine how islands will be formed and where load will remain intact. **Response: The SDT believes the standard should define what is required of the Planning Coordinators without being prescriptive as to how the requirements should be fulfilled. The SDT also notes that due to differences in physical system characteristics between regions, the process for identifying islands is best left to the Planning Coordinators in each region rather than attempting to put them into a continent-wide standard. Comments received during the two postings indicate industry support for this approach. A regional standard may be considered if the continent-wide standard is not specific enough.**
ReliabilityFirst Corporation	SDT has to develop a mechanism to make sure all the loads are accounted for.
Response: The SDT has modified the applicability to include both Distribution Providers and Transmission Owners as UFLS entities. It will be up to the Planning Coordinators as to how this objective will be achieved so that the performance characteristics may be satisfied.	
Arkansas Electric Cooperative Corporation	R7.2 the wording "... trip at or below 61.8 Hz" implies that any generator with a trip setting below 61.8 must be modeled. If a generator has an UNDER-frequency trip setting below 58 Hz then it falls into this catagory. Was this the intent? If the intent was to capture those units with OVER-frequency trip setting above 61.8 Hz then the wording needs to be changed to "trip at or above 61.8Hz".The drafting team did a good job.
Response: Thank you for this comment. The SDT has modified these requirements to refer to frequency-time curves rather than specific thresholds, and has incorporated your suggestion to specifically refer to overfrequency and underfrequency trip settings.	
System Protection & Control	There needs to be clarification as to loads and generation in this standard. If the intent is for the System to be secure for loss of xx amount of generation at summer peak and at winter peak in the planning model then that should be stated. In short, there needs to be further clarification on the relationship in regards to compliance within the Planning Model and the actual System Loads and Generation. Some entities in some regions require compliance with load shed percentages real time, 24/7. Others, only for the summer peak, and others for both summer and winter peaks. While these questions relate to measurements, it would

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	be beneficial to know beforehand the SDT's thinking on these before implementation begins.
Response: The proposed standard leaves this aspect of UFLS program design to Planning Coordinators as long as the performance characteristics (now R3) are satisfied for the load levels assessed (R4).	
Duke Energy	--- Similar to the response for 5, the team should consider simplifying the requirements by stating points that are just an offset of the PRC-024 requirements. As noted in the webinar, the overfrequency points do not coordinate with the PRC-024 curve at
Response: Thank for your comment. Based on industry input the SDT has replaced the discrete points in the proposed standard with a continuous curve that provides consistent 0.2 Hz margin for time up to 60 seconds.	
Illinois Municipal Electric Agency	IMEA recommends the following language from the Background/Information section of the comment form be included under Section B. Requirements, R2: Planning Coordinators may elect to use their Regional Standards Development process to develop the programs (but this is not required) or they may determine that their existing programs fully meet the requirements of this proposed continent wide standard. **Response: The requirements in the standard are intentionally limited to what an entity must do to support a reliability need. While the SDT agrees that Planning Coordinators may elect to use the Regional Standards Development process to develop the programs, such explanatory text is not appropriate within a reliability standard.** IMEA believes the standard should only apply to areas where there are required UFLS programs that are in existence and not applied to all load if those loads are already covered in an existing UFLS program. **Response: To ensure reliability and uniformity of UFLS program objectives, all load must be considered in a UFLS program and all UFLS programs must meet the requirements of the proposed standard, regardless of how existing programs are implemented. This being said, Planning Coordinators have flexibility to make allowances for issues such as what the commenter raises.** IMEA also recommends that Regional Entities be directed to not include registered functions other than PC, TP, and DP in the applicability section of their region-specific PRC-006 standard. **Response: Regional Standards may assign applicability to entities not included in the continent-wide standard as long as requirements do not conflict with the continent-wide standard.**
Hydro-Québec TransEnergie (HQT)	HQT recommends that NERC develop standards for unit governing response that are consistent with and support the reliability objectives of standards PRC-006 (UFLS) and PRC-024 (Generator Performance). **Response: The SDT agrees, though this is outside the scope of its activities.** HQT also notes that it may not be possible for the Planning Coordinators to design a reliable UFLS program that will arrest and

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	recover declining frequency if an excessive number of generators are exempted from meeting the underfrequency performance requirements in PRC-024. **Response: The SDT agrees, though this needs to be addressed by the Project 2007-09 (Generator Verification) PRC-024 SDT. The current draft of PRC-024 does require documentation and response to technical review by other entities for any non-conforming trip settings.** HQT, being in the Québec Interconnection, has technical parameters that differ from those specified in Requirements R6 and R7. A Variance will be needed to address those specific concerns in regards to frequency tresholds and parameters. **Response: A variance for the Québec Interconnection is included in the third posting of the standard.**
AEP	Wouldn't PRC-006-01 R5 be a SPS with all of it's attendant liabilities. Isn't NERC trying to minimize SPS schemes? **Response: A relay scheme that intentionally separates a portion of the BES likely would be classified as a Special Protection System (SPS). However, the SDT points out that the proposed standard does not require implementation of such schemes. The standard only acknowledges that such protection schemes may be implemented and requires that in such cases the resulting islands must be included in assessments of the UFLS program design.** PRC-006-01 R5 and EOP 003-1 philosophy would need to agree. PRC-006-01 R5 is written from the standpoint that one is able to predict island formation whereas EOP 003-1 is written to respond to island formation in whatever form it takes by shedding load (EOP 003-1 R6). **Response: The SDT also notes that while PRC-006 requirement R5 (now R2) is written from the perspective that one is able to predict some islands to be used as a design basis for the UFLS program, the overall intent of the standard is to design a UFLS program capable of operating reliably in response to island formation in whatever form it takes. Nevertheless, the SDT agrees that PRC-006-1 and EOP-003-1 should not include duplicative or contradictory requirements. The SDT has requested and received Standards Committee approval to propose a supplementary SAR to modify EOP-003-1. The proposed supplemental SAR and conforming revisions to EOP-003-1 have been included with the third posting of PRC-006-1.** EOP 003-1's purpose is to protect the interconnection whereas PRC-006-01 R5 would seem to require opening up ties. There seems to be a disconnect here. However, if the UFLSDT does goes forward with this thinking, then AEP would suggest small island formation as likely being more successful than large island formation. **Response: As noted above, the proposed standard does not require opening ties.** Another interpretation of the two standards would be that PRC-006-01 R5 is intended to be designed as an automatic first option. If that option fails, then EOP 003-1 is to be followed by the transmission operator. **Response: The SDT believes the commenter's alternate interpretation of the differences between EOP-003 and PRC-006**

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	is correct. The SDT has proposed revisions to EOP-003-1 to clarify these differences.
Ontario Power Generation	The SDT should be commended for producing a very good standard. There is one issue however that may negate the outcome of UFLS effort. Maximum permissible frequency overshoot of 61.8 Hz specified in R6.3 appears too high. It would quite likely result in hard to predict loss of many large fossil and nuclear units. Past system disturbances provide enough evidence of such thermal power plant response that typically leads to system collapse. This is a fundamental issue for the design of an effective UFLS scheme. What was the reason for not adopting a lower frequency overshoot value, especially considering that multi-step UFLS schemes should be able to accommodate that?
Response: The 61.8 Hz limit on overshoot was selected to coordinate with the generator tripping limits proposed in PRC-024 by the Generator Verification SDT (GV SDT). The GV SDT developed the tripping limits to coordinate with generating unit capabilities as provided by a number of manufacturers. Therefore, this comment should be directed to Project 2007-09 SDT. The SDT notes that even with a multi-step program it may not be possible to limit overshoot to a lower threshold depending on the physical characteristics of the island such as inertia and frequency response.	
We Energies	We Energies disagrees with the overall approach that the Standard Drafting Team (SDT) has taken with the latest draft of the continent-wide UFLS standard. FERC rejected the original PRC-006 due to its fill-in-the-blank nature. The continent-wide standard is still a fill-in-the-blank standard with the Planning Coordinator (PC) required to fill in the blanks. **Response: The SDT disagrees that the proposed standard is a fill-in-the-blank standard. The existing PRC-006 requires that the RROs consider a list of items in developing a program. The proposed standard requires that Planning Coordinators design a UFLS program that meets specific performance characteristics. While the proposed standard is not specific on how the program should be designed, it does establish clear requirements on what performance characteristics the program must meet.** In addition, the standard does not require the PC to involve the Distribution Provider (DP) and Transmission Owner (TO) in the development of the UFLS program. Also, the standard requires the DP and TO to implement without question whatever UFLS program has been designed by the PC. **Response: While the standard does not require that the Planning Coordinators involve other entities, the Planning Coordinator must work closely with other entities in performance of its role. Regardless, the SDT believes the Planning Coordinator is the Functional Model entity with the wide-area view and technical skills required to perform the UFLS design and assessments. The SDT has not included a requirement to involve the Distribution Providers and the Transmission Owners in the process because it would be difficult to measure "involvement" and because this involvement is not required to fulfill the reliability objective of the proposed standard.** We are concerned that the standard places a burden on the DP and TO to shed additional load to make up for generators which trip outside of the criteria specified in draft NERC standard PRC-024. **Response: The proposed standard does not necessarily require the Distribution Provider and Transmission Owner to**

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	shed additional load as suggested by the commenter. The proposed standard allows Planning Coordinators to determine what measures will be included in the UFLS program design to account for the impact of generators with non-conforming trip settings. The current draft of PRC-024 does require documentation and response to technical review by other entities for any non-conforming trip settings. A continent wide UFLS standard must set the minimum level of UF tripping for each Interconnection. The continent wide standard must do this by specifying the minimum amount of loadshed, trip frequency steps, and time delay criteria for UFLS relays. **Response: The SDT disagrees with this statement. The SDT has proposed and industry comments have generally supported the concept of a responsible entity designing UFLS programs to achieve certain performance characteristics without the standard having to specify the UFLS program details and parameter values.** The continent wide standard must remain silent on criteria, such as islanding, that is above and beyond the minimum amount of loadshed, trip frequency steps, and time delay criteria. Regional UFLS standards must be the vehicle for going above and beyond the minimum requirements of the continent wide UFLS standard. Islanding is one aspect that can be addressed in regional standards if necessary. If the above comments are not adopted by the SDT, the following additional comments address the standard as written. **Response: The proposed standard is silent on performance characteristics for islands that may form with a generation-load imbalance greater than 25 percent.** As mentioned previously, this standard does not have a requirement for the PC to involve the DP and TO in the design of the UFLS program. In addition, the standard requires the DP and TO to implement without question whatever program the PCs design without any concurrence from the DPs and TOs. There must not be any loopholes in this standard which would force the DP or TO to shed additional load for a generator that could meet the criteria specified in draft NERC standard PRC-024. Therefore, R2 must be revised to add a sentence that requires the PC to involve the DP and TO in the design of a mutually agreeable UFLS program. Similarly, R10 must be revised such that it states that the DP and TO will implement the mutually agreed to UFLS program. **Response: As noted above, the SDT has not included a requirement to involve the Distribution Providers and the Transmission Owners in the process because it would be difficult to measure "involvement" and because this involvement is not required to fulfill the reliability objective of the proposed standard. Also, the SDT has decided not to be prescriptive as to what measures will be included in the program design to account for the impact of generators with trip settings that trip above the curve in PRC-024.** Lastly, in the RFC region there are only three PCs. This standard is placing a burden and regulatory risk on these three entities in RFC. It is not consensus for three entities to dictate a UFLS program for an entire region. **Response: As noted above, the SDT believes the Planning Coordinator is the Functional Model entity with the wide-area view and technical skills required to perform the UFLS design and assessments. The Planning Coordinator is also**

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	supposed to coordinate with other entities in the performance of its role. The SDT believes the Planning Coordinator is the appropriate entity regardless of the number of Planning Coordinators within a region. The last sentence of R4 needs two clarifications. First, the text neighboring entities needs to be defined. It is unclear if the text neighboring entities refers to a neighboring PC, DP, TO, GO, Region, etc. Second, the term assessment needs to be referenced in a more specific manner. Does the term assessment refer to island assessments or the UFLS program assessment required in R7 **Response: This requirement has been removed.** The last bullet item in R5 needs clarification. First, what is meant by the text at least one island? Does this mean the default island is the Region's electrical boundaries? **Response: R5 (now R2) has been modified to state that either the Regional Entity footprint or the interconnection must be identified as an island.** Second, if a DP or TO's load is part of multiple islands, what mechanism will prevent the DP or TO being issued conflicting UFLS trip settings (e.g. Island 1 requires the DP to set its relays to trip at 59.0 Hz, while Island 2 requires that same DP to set its relays to trip at 58.7 Hz)? **Response: The Planning Coordinator must design a UFLS program for application across its footprint and the program design must meet the performance characteristics for all islands studied. If there are still conflicting instructions, the matter should be resolved with the Planning Coordinator.** R7.1 and R7.2 need to be revised since as these sub-requirements are currently written all units with automatic UF tripping installed would be required to be simulated. Specifically, R7.1 requires units that trip between 58.0 Hz to positive infinity to be simulated and R7.2 requires units that trip between 61.8 Hz and 0 Hz to be simulated. **Response: These requirements (now Parts 4.1 through 4.6 of Requirement R4) have been revised such that Part 4.1 refers specifically to underfrequency and Part 4.2 specifically refers to overfrequency.**
Response: See in line responses.	
PacifiCorp	No comment.
NextEra Energy Resources, LLC	No comment.
American Transmission Company	ATC believes that the SDT should develop official definitions for the following three terms used throughout the document: a) "under-frequency load shedding" (along with under-frequency load shedding program) b) island and region. All three terms

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	warrant a definition in order to be able to assess whether the plans developed pursuant to the standards are consistent between and among the Planning Coordinators. Although these terms may have some generally accepted meaning, there likely is a difference among Planning Coordinators and those differences could potentially lead to enforcement issues. The failure to define these terms by NERC will result in each Planning Coordinator providing their individual perspective that could result in either gaps in the region or difference in what is meant by an island within a region, and what constitutes an under-frequency load shedding program. **Response: The SDT believes use of these terms is generally understood throughout the industry and unique definitions are not required in the NERC glossary. The SDT believes the meaning of "underfrequency load shedding" is already understood by industry in implementing the approved PRC standards. The term "island" is used exclusively to refer to a portion of the system that is isolated electrically from the rest of the system. The term "region" is used as it relates to the traditional sense of the defined boundaries of a Regional Reliability Organization (RRO). The term "region" has been replaced by "Regional Entity footprint" in the third draft.** R2 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall design . . . that was developed in coordination with the applicable regional group(s). **Response: The group of Planning Coordinators concept has been removed and the responsibilities have now been assigned to individual Planning Coordinators.** R2 - To allow appropriate UFLS program differences amoung islands within a single Regional Entity, we suggest this rewording, " . . . under frequency load shedding programs for consistent application across each island within the Region." Some islands in the MRO need to shed more load than other to achieve reasonable frequency recovery. **Response: The SDT has addressed this concern in an alternate manner by eliminating the word "consistent."** R3 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall develop . . . in coordination with the applicable regional group(s) to apply to select portions of the Bulk Electric System that are designated as islands?.R4 To make the requirement apply to each PC rather than a group and include corordination within the Region, we suggest this rewording, Each Planning Coordinator shall develop a procedure for coordinating with groups of Planning Coordinators within its Region(s) and groups of Planning Coordinators in neighboring regions . . .R5 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall identify . . . as a basis for designing a UFLS program with the applicable regional group(s) R6 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall specify . . . load shedding program in coordination with the applicable regional group(s) that are required to meet the following . . . **Response: As noted above, the group of Planning Coordinators concept has been removed and the responsibilities have now been assigned to individual Planning Coordinators.** R6.1 To match the design emphasis that is included in R6.2 and R6.3, we suggest . . . no less that 58.0 Hz per simulated event.

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	Response: The SDT has revised these requirements to refer to frequency-time curves rather than specific thresholds and time durations. The SDT believes that the revised requirements (now Parts 3.1 and 3.2 of R3) address the commenters' concern. R7 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall conduct . . . with its applicable regional group(s). R8 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall create . . . in coordination with its applicable regional group(s) . . **Response: As noted above, the group of Planning Coordinators concept has been removed and the responsibilities have now been assigned to individual Planning Coordinators.** R8 - Since the interpretation of "annually" can vary widely, we suggest this rewording, "each calendar year and within 15 months of the last update". **Response: Since "annually" is not defined a NERC term, it has the meaning "occurring or happening every year or once a year." as found in a collegiate dictionary. The SDT believes the reliability objective of this requirement is met without specifying details of when during the year the requirement is fulfilled.** R9 Since the Transmission Owner reference is redundant, we suggest this rewording, Each Distribution Provider shall provide.. .. **Response: The SDT has decided to retain both the Distribution Provider and the Transmission Owner as UFLS entities in the applicability for this requirement. The drafting team provided the rationale for keeping Transmission Owner in response to comments to Question 1B.** R10 Since the Transmission Owner reference is redundant, we suggest this rewording Each Distribution Provider shall provide . . . **Response: The SDT has decided to retain both the Distribution Provider and the Transmission Owner as UFLS entities in the applicability for this requirement. The drafting team provided the rationale for keeping Transmission Owner in response to comments to Question 1B.** R11 - Since reactive power device overvoltage or underfrequency protection may be essential to the UFLS program assessment, we suggest adding the Requirement, "R11. Each Distribution Provider and Transmission Owner shall provide its reactive power device overvoltage or underfrequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section. **Response: The database is intended to document the load tripping implemented by Distribution Providers and Transmission Owners to meet Requirement R9. In fulfilling the Planning Coordinator function, the Planning Coordinators have the ability to obtain protection settings they need to model to comply with R4 and R11. Planning Coordinators and Transmission Planners routinely obtain similar data to perform planning studies required by the Transmission Planning (TPL) standards.** R12 - Since reactive power device overvoltage or underfrequency protection may be essential to the UFLS program design, we

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	suggest adding the Requirement, "R12. Each Distribution Provider and Transmission Owner shall reactive power device tripping in accordance with the UFLS program desinged by the group of Planning Coordinator for each region in which they operate." **Response: The SDT has added a new requirement R10 that requires Transmission Owners to provide automatic switching of Elements in accordance with the UFLS program design. The SDT believes this general requirement is more appropriate to include both energizing and de-energizing reactive devices or any other system Elements when included by the Planning Coordinators as Part of the UFLS program design.** R13 - Since generator off nominal frequency protection information may be essential to the UFLS program assessment, we suggest adding the Requirement, "R13. Each Generator Owner shall provide its off nominal frequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators." R14 - Since the coordination of generator off nominal frequency protection is essential to the UFLS program design, we suggest adding this Requirement "R14. Each Generator Owner shall have evidence that they provided any coordination that is required by the applicable regional group of Planning Coordinators to meet UFLS program specifications." **Response: The SDT does not believe these requirements are necessary. Per R5 of the first draft of PRC-024-1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. Adding such a requirement in PRC-006-1 will create a redundant data requirement already contained in PRC-024-1. Coordination is not required from Generator Owners, but PRC-024 does require documentation and response to technical review by other entities for any non-conforming trip settings.** Reference Document - Due the number and complexity of the elements that need to be considered to develop effective UFLS program designs and for fulfilling the requirements in this standard (e.g. island identification, number of load tripping steps, frequency settings, time delays, percentage of load per step, system inertia, governor response, etc.), we suggest that a reference document be developed to provide useful information regarding automatic UFLS programs to the applicable entities. **Response: The SDT appreciates the complexities of designing a UFLS program; however, the SDT notes that regional UFLS programs have existed for forty years and believes that the Planning Coordinators have adequate expertise to understand the requirements of the proposed standard.**
Luminant Power	Several of the requirements are for a group of Planning Coordinators. From a Compliance perspective, how will the actual requirements be enforced on the group, or will the requirements be enforced on each individual Planning Coordinator? **Response: The group of Planning Coordinators concept has been removed and the responsibilities have now been assigned to individual Planning Coordinators.**
Ameren	There is nothing in the standard that provides direction in terms of measuring whether an entity has effectively implemented a

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	UFLS program.
Response: Requirement R9 requires that Transmission Owners and Distribution Providers provide automatic tripping of load, and Requirement R10 requires that Transmission Owners provide automatic switching of Elements in accordance with the UFLS program designed by the Planning Coordinator. These requirements establish that the Distribution Providers and the Transmission Owners must implement what is required of them according to the UFLS program design.	
FirstEnergy Corp	1) On requirement R7.1 we suggest adding the words under-frequency before the phrase trip settings for clarity. **Response: This requirement (now Parts 4.1-4.3 of Requirement R4) has been revised such these Parts refer specifically to underfrequency.** 2) On requirement R7.2 we suggest adding the words over-frequency before the phrase trip settings for clarity. **Response: This requirement (now Parts 4.4-4.6 of Requirement R4) has been revised such that these Parts refer specifically to overfrequency.** 3) As stated in question 5, the frequency requirements for generators should be in this standard PRC-006 not PRC-024. **Response: The SDT disagrees and has coordinated with Project 2007-09 SDT such that Generator Owner frequency and voltage Requirements can appear in one place (in PRC-024). Coordination between the two SDTs is expected to accomplish the same reliability objectives as if the frequency requirements for Generators Owners were in PRC-006.** 4) The new standard does not properly address the requirements of PRC-009 to analyze the performance of an UFLS program following an under frequency event. If the standard is retire PRC-009, it needs to properly cover the analysis of these events and not refer them to ERO Rules of Procedures. Since PRC-004 covers the analysis of System Protection misoperations and PRC-016 covers SPS misoperations, UFLS events including misoperations also must be covered in a standard to ensure review. **Response: The SDT has added a requirement to include an assessment of the performance of UFLS equipment and the UFLS program effectiveness (Requirement R11) within one year of an actuation of UFLS resulting in a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program.** 5) On requirement R.1 the use of the word region should be replaced with Regional Enity territory for clarity so that region may not be misinterpreted to be RTO region or some other sub-region of a Regional Entity territory. We suggest the requirement be written to say Each Planning Coordinator shall join a group consisting of all Planning Coordinators within the Regional Entity territory it performs the Planning Coordinator function. **Response: The term "region" is used as it relates to the traditional sense of the defined boundaries of a Regional Reliability Organization (RRO). The term "region" has been replaced by "Regional Entity footprint" in the third draft.** 6) We support the following MISO comment. R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a

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	PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria. Response: The SDT recognizes the difficulties that could be encountered in identifying islands. Nevertheless, there may be portions of a system that obviously have a higher likelihood of islanding as compared to others. How extensive an analysis to identify islands needs to be is a judgment that cannot be written into a standard and must be left to the discretion of the Planning Coordinators involved. The standard only requires that criteria for identifying islands be developed, documented and applied.
CenterPoint Energy	1. CenterPoint Energy again commends the SDT for addressing the difficult issue of Applicability. CenterPoint Energy suggests the SDT also address the difficult issue of placing requirements within the proper category of reliability standard. CenterPoint Energy recommends placing Requirement 9, dealing with submittal of UFLS data, within a MOD standard (Modeling, Data, and Analysis). CenterPoint Energy believes the UFLS data will be used for modeling to facilitate dynamic simulation studies and, therefore, should be included in an MOD standard. **Response: The SDT does not disagree with the commenter, but including the requirement in the MOD project may create a reliability gap if the MOD project is not completed before or at the same time as the UFLS project. As a result, the SDT feels that this requirement needs to remain in this standard, at least for the present time.** 2. CenterPoint Energy appreciates the SDT attempt to clarify islanding. However, the SDT may have misinterpreted CenterPoint Energy comments on Draft 1. Reiterating our comment, CenterPoint Energy believes regional and/or predetermined islanding is not always applicable in an interconnection-wide region. In addition, the requirements dealing with a group of Planning Coordinators are also not applicable to an interconnection-wide region, such as WECC and ERCOT. With eight of the ten proposed requirements applicable to a group of Planning Coordinators, it appears eight requirements will be problematic for WECC and ERCOT. CenterPoint Energy recommends the following wording be included in Requirements 1 through 8: This requirement is not applicable in an interconnection-wide region. **Response:** The SDT recognizes the difficulties that could be encountered in identifying islands. Nevertheless, there may be portions of a system that obviously have a higher likelihood of islanding as compared to others. How extensive an analysis to identify islands needs to be is a judgment that cannot be written into a standard and must be left to the discretion of the Planning Coordinators involved. The standard only requires that criteria for identifying islands be developed, documented and applied. **The group of Planning Coordinators concept has been removed and the responsibilities have now been assigned to individual Planning Coordinators.**
Independent Electricity System Operator	(1) We propose R5 to be expanded to require the Planning Coordinators to develop criteria for identifying potential islands, as follows: Each Planning Coordinator shall develop criteria, considering historical events and system studies, to select portions of the Bulk Electric System (BES) that can form an island(s) as a basis for designing a UFLS program. The identified island(s) shall

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	include: **Response: It is unclear if the commenter is suggesting that the requirements to develop criteria and to identify islands should be combined into one requirement. If so, the SDT thinks that these two requirements cannot be combined into one requirement because they are describing two separate activities.** (2) R6 needs to be more precise regarding load. Suppose a station with 100MW of load has 20MW of distributed generation added that is anticipated to be in service during the ULFS calculation period (e.g. summer peak hour). Is the ULFS arming determined on basis of 100MW or 80MW of load This will make a big difference in Ontario if the GEA attracts significant amounts of the distributed generation. **Response: The load in the imbalance equation Requirement R6 (now R3) is based on the Planning Coordinator's load forecast which should be reflected in the power flow model. The 25 percent load-generation imbalance requirement should be consistently applied even if some generation is netted with load. The actual arming would be in accordance with the load amounts specified by the UFLS program designed by the Planning Coordinator.** (3) The standard should include a requirement for mandatory testing/re-calibration period for both ULFS relays and generator under and over frequency relays. The Generator Operator/Owner needs an obligation to provide this information. **Response: Testing and recalibration of relays is addressed by the Protection System Testing and Maintenance SDT (Project 2007-17) in PRC-005-2.** (4) Governor action can help mitigate adverse effects of disturbances that affect frequency. Should this standard include some requirements for governor response? **Response: The SDT agrees that governor response has a direct impact on recovering frequency and controlling frequency overshoot. However, specifying requirements for governor response is outside the scope this standard. The UFLS program must be designed to meet the performance characteristics for whatever level of governor response is present on the system.**
Xcel Energy	We feel R6.4 is not complete without consideration of other BES components, such as transformers and reactive devices. To ensure excessive voltage does not cause further damage or perpetuate the situation, we feel these additional components should be considered. **Response: The reliability objective of this performance characteristic in Requirement R6 (now Requirement R3) is to prevent tripping of generation that would exacerbate the load-generation imbalance. This is the reason the SDT focused on generator busses and generator step-up transformer high-side busses in requirement R3 Part 3.3. The SDT believes that observance of overvoltage limits on other equipment should be addressed by other standards, not a UFLS standard.** We feel that the use of the word region in R1 is unclear. We assume the SDT intended to refer to the 8 NERC regions? (MRO,

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	SPP, WECC, RFC, SERC, etc.) If so, please make that clear in the requirement. **Response: The SDT intended "region" to relate to the traditional sense of the defined boundaries of a Regional Reliability Organization (RRO) and its successor the Regional Entity. The SDT feels that the concept of a "region" is generally understood throughout the industry and does not believe that a unique definition is required. The term "region" has been replaced by "Regional Entity footprint" in the third draft.**

1) Individual or group.
Individual

2) Name
Barry Francis

3) Organization
Basin Electric Power Cooperative

6) NERC Region (check all Regions in which your company operates)
MRO
WECC

7) Registered Ballot body segment (check all industry segments in which your company is registered)
1 - Transmission Owners
3 - Load-serving Entities
5 - Electric Generators

Summary Considerations:

The SDT believes that what is behind the majority of the commenter's comments is a concern over sub-regional UFLS programs that need to be substantially more than 25 percent.

First, the SDT would like to clarify a possible misconception held by the commenter: The performance characteristics in R6 (now R3) of the draft PRC-006 standard would NOT apply to UFLS program percentages and load-generation imbalances over 25 percent. It is correct that the generator off-nominal frequency tripping limits contained in the draft PRC-024 standard would apply at any UFLS percentage and imbalance. However, a UFLS program capable of shedding more than 25 percent of a system's load would only need to comply with the performance characteristics up to a 25 percent load-generation imbalance. Beyond a 25 percent load-generation imbalance, a UFLS program would not be subject to any NERC imposed requirements, although the Planning Coordinators within a region could devise other performance characteristics that would apply under load-generation imbalance scenarios greater than 25 percent.

The SDT understands the concern over bigger sub-regional UFLS programs. The SDT recognizes that Planning Coordinators in a region with a 60 percent capable UFLS program, for example, may have trouble complying with the performance characteristics even under a 25 percent load-generation imbalance scenario. The SDT is not convinced that it would be impossible to comply, but can see that it could be more difficult. In response to this concern the SDT did modify the underfrequency performance characteristic (part 3.1 of Requirement R3) noting that some entities may have difficulty recovering frequency within 30 seconds. Assessments that demonstrate the reliability objective of PRC-006 can be met without meeting the performance characteristics in Requirement R6 (now R3) could be used to support a request for a regional variance.

The commenter does not seem to acknowledge the need for coordination among interconnected regions, a consideration that has weighed heavily in the SDT's deliberations. This may be because coordination can become troublesome in the presence of bigger programs. A bigger program in an exporting sub-region with limited interconnecting transmission, for example, is likely to set up further system separations should a UFLS event occur across a larger area. On the other hand, a bigger program in an importing sub-region should not cause coordination difficulties. The SDT has determined that the approach that is least intrusive on the flexibility to set UFLS design parameters within a region, but that addresses the need for inter-regional coordination, is to establish continent-wide performance characteristics as are now in the draft standard.

The SDT disagrees that there is a need to radically modify the two standards (PRC-006-1 and PRC-024-1) as the commenter is suggesting. Most of the North American systems have UFLS programs in the 25-30 percent of load range and should have no difficulty in complying with the draft performance characteristics. The Planning Coordinators within a region are not obligated by the draft standard to constrain the size of sub-regional programs for the sake of interregional coordination or any other reason. If necessary, a regional variance may be proposed.

The commenter's comments on PRC-024 seem predicated on an assumption that GOs will set their relays on this curve. The SDT suggests the commenter comment on the draft PRC-024 standard on this point. Nonetheless, generator underfrequency tripping curves are not new. The MRO region, even today, has such a generator underfrequency curve (stair-step) that fairly closely tracks the draft PRC-024 curve. Therefore, the SDT is not certain that the commenter's comments regarding

coordination of UFLS with generator tripping and elimination of these curves has been found necessary even in regions having sub-regional UFLS programs substantially greater than 25 percent. (Note: the commenter should re-review draft PRC-024 Attachment 1, Off-Nominal Frequency Capability Curve, because the time durations are longer than what the commenter has assumed in the commenter's Question 5 comments and in section 2.17 of Question 8 comments.)

8) Question 1a
Do you agree that creating a continent wide standard preserves the intent of utilizing specific expertise within the regions to develop UFLS programs that meet common performance characteristics? Yes

Summary of Issues - Question 1:

- Technical approach is inappropriate and the team should provide its technical justification for the performance criteria

  Response: The SDT disagrees that the technical approach is inappropriate. The technical justification for the performance characteristics lies chiefly in their coordination with generator under-frequency tripping limits in draft standard PRC-024, which in turn are based on turbine manufacturer's permissible life-time durations at off-nominal frequencies.

- Agrees that planning coordinators are the appropriate entity to establish the program; however, there are shortcomings to this approach – limited scope and should include subject matter experts (the planning coordinator may not be the subject matter expert). The Regions should remain involved in the process of developing the programs as they have the committee structure in place to accomplish.

  Response: The SDT thanks the commenter for his support; however, does not see an alternate approach to assigning responsibility to the Planning Coordinator. FERC Order 672 indicates that requirements should be assigned to users, owners, operators of the bulk electric system and while the SDT agrees that the Regional Entities should be involved, the drafting team can only assign the responsibility to the Planning Coordinator (a user, owner, operator). The drafting team feels that it has not precluded the involvement of the Regional Entity in the process nor precluded the Planning Coordinator(s) from electing to use their regional standards development (process as an open and inclusive process to establish the program.

9) Question 1a Comments:
See my detailed discussion under item 8, in it's entirety, but especially my sections 3.5 and 3.6. I believe a continent wide standard may be possible if we adopt a completely different type of measure but we cannot be setting performance details up front before the study work has been performed. Different sizes of programs have different performance characteristics, so a single set of performance characteristics will not meet the needs of all parts of North America.

Response: See SDT answer under Summary Considerations above. Most North American systems have UFLS programs in the range of 25-30 percent of load. If a sub-regional UFLS program substantially exceeding this range cannot comply with the performance characteristics for load-generation imbalances up to 25 percent, a regional variance should be proposed.

10) Question 1b
Do you agree that the SDT has assigned responsibility to the appropriate entity? No

11) Question 1b Comments:
I do not know for sure if responsibilities are assigned to the appropriate entity, so I answered NO, when "I do not know" might have been more appropriate. To some degree, everyone needs to get involved at some level to ensure we have a loading shedding program in place to act as a saftey net. I am concerned that the transitions associated with "mandatory compliance" appears to actually be decreasing the level of coordination we have traditionally had. Good coordination is the key to ensuring reliability. Among other things, we need to keep the NERC regions involved in this process. They have the committee structure to facilitate coordination matters, and they can bring everyone together to jointly focus on the issues.

Response: The Standard Drafting Team does not see an alternate approach to assigning responsibility to the Planning Coordinator. FERC Order 672 indicates that requirements should be assigned to users, owners, operators of the bulk electric system and while the SDT agrees that the Regional Entities should be involved, the drafting team can only assign the responsibility to the Planning Coordinator (a user, owner, operator). The drafting team feels that it has not precluded the involvement of the Regional Entity in the process nor precluded the Planning Coordinator(s) from electing to use their regional standards development process as an open and inclusive process to establish the program.

12) Question 2:
The SDT has strived to draft the applicability in a manner that includes all load while avoiding assigning applicability to more than one entity for the same load. The Functional Model indicates the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. Considering the Functional Model definition of Distribution Providers please indicate whether you believe it is necessary to assign applicability to "Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of a Distribution Provider's load". No

13) Question 2 Comments:
It seems OK to consider transmission owners with end-use load connected to their Facilities as Distribution Providers, but I can see complications. How does a transmission owner with a small amount of end-use load have enough load to work with to satisfy the load shedding program description? This implies they would have to coordinate with someone else. Taking this concept further, it seems like we need to ensure the right program is implemented in aggregate, but not worry too much about each responsible party meeting the exact program specification. We can take advantage of one party shedding a little too much at one stage and another shedding a little less to get the right fit in the end. This is sort of taking advantage of offsetting errors. This implies some type of group coordination based on geographic area is needed to ensure the collective load shedding need is fulfilled.

Response: The SDT acknowledges that entities with a small amount of end-use load could have difficulty shedding load in several small steps. The proposed standard only requires that the Distribution Providers and Transmission Owners follow the program developed by the Planning Coordinators in their region and does not specify the program requirements. The SDT believes it is appropriate to allow the Planning Coordinators in each region to address potential concerns related to small entities by the means they deem most appropriate. The SDT has also revised the applicability in Draft #3 and this revision may address the commenter's concerns in part.

Summary of Issues – Question 3:

- Planning Coordinators should determine the appropriate analysis. As written, the implication is that a full transient stability program is needed to do this analysis. There are other equally valid analytical approaches, each with different strengths and weaknesses, and the group of Planning Coordinators should be allowed to use whatever tools they feel are most appropriate for quantifying this risk.

  Response: The Planning Coordinators are permitted to use whatever methods, tools and analyses they wish to use in coming up with the UFLS program design and parameters. The draft standard would only require dynamic simulations of the whole regional system or the islands in the periodic UFLS assessments (now R4). The SDT believes that dynamic simulations are the most dependable means of assessing compliance to the performance characteristics. Equivalent inertia analysis would not include the effects of island initiating disturbances on localized frequency and voltage, inter-machine oscillations, or the particular response of individual unit governors.

- Should try to prevent units from tripping off before the UFLS program plays out

  Response: The SDT agrees, but the only way to ensure that units don't trip before UFLS plays out is to set coordinated requirements in standards. On this matter, PRC-024-1 is the applicable standard for establishing generator tripping requirements and PRC-006-1 establishes coordinated UFLS program performance characteristics.

14) Question 3:
The proposed continent-wide standard requires that Planning Coordinators model the trip settings of any generators that trip at or above 58.0 Hz (Requirement R8) when verifying through dynamic simulation that the UFLS program design is adequate to meet the continent-wide performance characteristics specified in Requirement R6.

Do you agree with this approach to ensure that effectiveness of the UFLS program is not jeopardized by units that trip at or above the minimum frequency (58.0 Hz) at which the UFLS program may arrest frequency decline? No

15) Question 3 Comments:
Some type of risk assessment is needed, but a dynamic simulation may not always be appropriate if there are other ways to get the answer we are looking for. This subject, and related topics, are addressed in the comprehensive discussion I included under item 8. Please consider all of my comments under item 8 to understand my concerns.

First of all, in some instances a regional (or sub-regional) load shedding program sheds more than the required minimum of load. A consequence is the expected minimum transient frequency will probably be below 58 Hz, at least for some set of conditions, so we are going to interpret "58 Hz" as 58 Hz or the minimum expected transient frequency of the regional (or sub-regional) program. This revised definition is what we consider to be important.

Some of the older wind generation will trip early due to inherent instability of that type of induction generation. This is not a planned activity, but it is still loss of additional generation. In MRO we felt the present magnitude of this impact was small (and unpredictable) and it could be included as part of the original assessment of the total load shedding requirement. (This will have to be reconsidered as additional wind generation is added.)

MRO expects that newer wind generation and virtually all of the conventional generation will be able to accommodate the generation off-nominal frequency tripping time delay requirements proposed by MRO. As far as we are aware, it appears the sole exception are owners of one model of gas turbine who may want to trip instantly at frequencies such as 58.2 Hz rather than accept brief dips below 58.2 Hz. In WECC, owners of similar units managed to comply with the comparable WECC generation off-nominal frequency tripping time delay standard. We hope this will be how it plays out in MRO after owners of these types of gas turbines take a closer look and their options.

MRO does not encourage the practice of premature tripping of generation but we made a provision in the MRO UFLS program definition to allow premature tripping on underfrequency provided it meets certain provisions. This provision also applies to small non-utility generation which might be on a feeder that is tripped with load. Basically we require a nearly identical size block of load to be shed at nearly the same time and location to compensate. Owners who wish to do this should have some responsibility to demonstrate they can satisfy this provision. The burden of proof should be on those who want an exclusion.

At this point we believe that the group of Planning Coordinators (or the applicable study group in general) should decide on the appropriate analysis method to review impacts. They can decide if such loss of additional generation is significant or not. If we are only dealing with one or two small units on a large system, then this hardly needs further study other than to demonstrate it is feasible to trip additional load at the time the generation trips. As far as assessments go, we feel there are various approaches that can be taken to do this type of risk assessment. As written, the implication is that a full transient stability program is needed to do this analysis. There are other equally valid analytical approaches, each with different strengths and weaknesses, and the group of Planning Coordinators should be allowed to use whatever tools they feel are most appropriate for quantifying this risk.

There are even ways to assess the risk of having units trip off early that do not rely on simulations, but instead just quantify the additional overload burden this adds to the island.

Let engineers figure out how to study the problems using whatever tools, methods, and calculations they feel are appropriate. However, as a general principle, we should try to prevent units from tripping off before the UFLS program plays out. Even more important, we should not allow any generation to trip via dedicated overfrequency relays (other than tripping actions directly or indirectly related to the inherent factory installed load rejection protection that we do not want to be messing with). The one exception would be when overfrequency tripping of generation is a planned activity that is a feature of the UFLS program used to rebalance load and generation.

16) Question 4:
The SDT added a requirement that requires the Planning Coordinators model, in the five year assessments, any automatic load restoration that is designed to assist in stabilizing system frequency (Requirement R9). The team decided to add this requirement as a result of a comment during the first posting. Do you agree that this requirement is necessary for reliability?
Yes

17) Question 4 Comments:
Any automatic feature of the load shedding program should be modeled in the ULFS Program assessment.

Response: The SDT agrees.

18) Question 5:
The SDT added a requirement in the underfrequency load shedding performance characteristics that requires (in simulations) frequency to not remain below 58.2 Hz for greater than four seconds cumulatively per simulated event (Requirement R6.2). The

SDT added this requirement to better coordinate with the Generator Verification Project (PRC-024) tripping curve. Do you agree with this additional requirement? No

Summary of Issues – Question 5:

- The team should provide technical justification for the performance criteria

  Response: The technical justification for the performance characteristics lies chiefly in their coordination with generator under-frequency tripping limits in draft standard PRC-024, which in turn are based on turbine manufacturer's permissible life-time durations at off-nominal frequencies.

- Overall load shedding performance and coordination with generation protection should be evaluated at the regional level (not continent wide level – inferred)

  Response: The creation of a continent-wide standard does not prohibit the creation of Regional Standards for UFLS. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. This approach still allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.

- Canadian portion of MRO cannot meet the performance criteria and MRO cannot meet the timeframe established in requirement R6

  Response: The standard has been revised with input from MRO. Please see R3 and Attachments 1 and 2 in Draft #3.

- Setting specific off-nominal frequency limits / criteria up front effectively sets the limit on how much load can be shed and drives all load shedding programs to the lowest common denominator which will reduce reliability

  Response: The SDT disagrees. For imbalances up to and including 25%, these performance characteristics must be met; however, the proposed standard does not include requirements for imbalances exceeding 25%. If a region wishes to design an UFLS program to cover imbalances exceeding 25%, the region's Planning Coordinators may develop other performance requirements through Regional Standards, Regional Variances, or Regional Criteria as outlined in the NERC Rules of Procedure.

19) Question 5 Comments:

Please provide the technical justification for this performance criteria.

This subject, and related topics, are addressed in the comprehensive discussion I included under item 8. Please consider all of my comments to understand my concerns.

We understand the SDT wants to ensure load shedding programs achieve quick frequency recovery and minimize underfrequency exposure. However we do not feel this requirement is the right way to go about that. This type of criteria is overly specific and should not be in the NERC standard. The recently developed MRO UFLS program which sheds 30% of system load appears to meet this criteria, but the Canadian portions of MRO which have higher load shedding requirements are unlikely meet this criteria. Aggressive load shedding programs in general will probably not satisfy this requirement. Frequency recovery, overall load shedding performance, and coordination with generation protection, should all be evaluated at the regional level by those who do the technical analysis of regional load shedding programs. In addition to study work, a lot of common sense needs to be applied. Several things need to be discussed to clarify our position.

First of all, we do not agree with the direction taken in PRC-024 to define off-nominal frequency settings for generation. That should never have been included as part of PRC-024. No technical justification was ever provided for the generation protection frequency setpoints and time delays suggested in PRC-024, and those setpoints and delays do not necessarily reflect actual equipment capabilities. NERC should not be defining generation off-nominal frequency protection standards such as those in PRC-024 unless this is only intended to be a starting point that can be adjusted, as needed, based on results of actual study work. It takes study work to define the expected worst case frequency recovery times of the load shedding program and off-nominal frequency exposure is strongly affected by the size of the load shedding program. Setting specific off-nominal frequency limits/criteria up front effectively sets the limit on how much load can be shed and drives all load shedding programs to the lowest common denominator. Obviously that will reduce reliability. Programs which shed more than the minimum required load will inherently experience lower frequencies and spend more time below 58.2 Hz.

We believe that load shedding program design should be based on achieving the quickest frequency recovery that is possible

subject to satisfying all of the other conflicting design requirements and constraints, such as minimizing overfrequency problems, and in the end you are left with the engineering realities of what settings are needed on turbine/generator protection to achieve coordination. The folks who do the analysis at the Region level are in the best position to judge what is appropriate in the end. Final recommendations for turbine/generator protection will involve trade offs and compromises that have to be resolved by engineering judgment and a good deal of common sense.

We would like to point out that the risk to generation is somewhat less than implied by the generation underfrequency protection time delay settings and that being too conservative on the generation protection side will be a risk to system reliability. Consider that if premature generation tripping occurs that we are likely to initiate cascading loss of generation and go black. (The real loss of life exposure to power plants might be the restoration process of a black start plan, a plan which usually calls for this underfrequency protection to be disabled up front so they can pick the pieces back up.) In the context of a load shedding event, the risk to units is based on actual off-nominal frequency exposure, which is inherently something of a probability density function. For any load shedding program there are going to be certain combinations of overload and modeling assumptions where UFLS programs tend to stall out or where frequency recovery is sluggish. Think of this as narrow windows of vulnerability. For the majority of the conditions modeled, the frequency recovery is much quicker. A well designed UFLS program which is designed to force frequency recovery back towards 60 Hz can actually act as the first line of defense for generation and this is how the new MRO program was designed.

Even more troubling to MRO, and this should be equally troubling to all of the NERC Regions, are the very short time delays the PRC-024 has proposed at the higher frequencies (below 58.5 Hz for <= 10 seconds, below 59.3 Hz for <=30 seconds). In the MRO program design work, for the US portion of MRO where we have the smallest load shedding requirement, we spent approximately 8.7 seconds to 1.4 seconds below 58.5 Hz depending on what was assumed for governor response and other modeling details. The 10 second requirement for 58.5 Hz was just barely satisfied but keep in mind that we also want to set generation trip times so we have some comfortable margin between expected frequency recovery times and generation trip delays in case "real world" complications slow down frequency recovery. Likewise case work shows we will be below 59.3 Hz for 58.4 seconds to 42.5 seconds depending on governor action and other modeling assumptions. This is longer than the proposed 30 second limit. The final recommendation of the MRO program was to require generation protection to have a minimum of a 300 second delay for the frequency band between 59.0 Hz and 59.3 Hz (10 times the delay recommended in PRC-024), and a 45 minute delay for the band between 59.3 Hz and 59.5 Hz (270 times the delay recommended in PRC-024). Further, we recognize that programs which shed more than 30% of load will need to relax these settings and accept greater time delays. Keep in mind the MRO program was designed to work even if we get no net governor type of action as we use additional small blocks of load shed on delay to kick us towards 60 Hz if recovery is slow. We felt we got the quickest frequency recovery that was possible subject to all the other constraints we had to deal with, like limiting overfrequency and achieving relay coordination. We factored in considerable uncertainly into the design, but what may happen in the real world when everything else is going wrong can be chaotic and cannot always be anticipated. All of us in the industry really need to consider that when deciding how to set generation off-nominal frequency protection. Units can accept considerable time at frequencies closer to 60 Hz, and can generally operate continuously at +/- .5 Hz off of 60 Hz. The time delay associated with the 59.3 Hz setting proposed in PRC-024 is only 30 seconds which is way shorter than actual equipment capability (based on a reasonable accelerated loss of life per event). The system should be capable of operating at 59.3 Hz in excess of 30 minutes. In real life you would never want to set generation protection with a 30 second delay at 59.3 Hz. That is bound to cause trouble. In real life, the unexpected is going to eventually happen and our "perfect program on paper" will get a reality check. If frequency stalls out around 59.3 Hz, the actual equipment capability allows enough time for system operators to take manual actions. The proposed time delay in PRC-024 is too small to allow manual actions. Some may think that with a perfect automatic UFLS program that we can design things so this will not happen. Wrong, things can always get worse, Murphy's Law applies. We recognize that even the best UFLS program can fail in real life as everything else goes wrong out on the system. All load shedding gives us is a good chance of survival, but we can never assure ourselves it will always work as desired in the face of the unexpected. We need to constantly anticipate what can go wrong and eliminate as much of this inherent risk as we can, but we can never provide a safety net that will work for all modes of system failure. Here is a real world example of how we could stall out at some frequency such as 59.3 Hz (or any other frequency below 60 Hz for that matter). When load shedding occurs, there is a chance the system may break up further as tie lines between remote generation and load centers become over taxed and the two systems may lose synchronism (this cannot always be anticipated up front). The result is that subislands form where one is now surplus in generation and one has too much load. The island which is surplus in generation is now at risk of losing generation on overspeed (probably due to internal problems at each plant, especially thermal plants, that lead to random tripping that is nearly impossible to quantify). Once generation trips the island will plunge into a 2nd round of underfrequency. Fortunately loss of the first unit might allow the others to survive (i.e. steam valves can open back up) so the final imbalance might still be manageable. However in this instance, the region has already used up part or all of the automatic load shedding capability. With luck this island will settle out at some frequency where operators will have enough time to manually drop load to force frequency recovery before generator underfrequency protection trips. Once generation underfrequency protection trips the first unit, the system will cascade and go black. To give enough time to do manual load shedding at this higher frequencies, you need to set long time delays on the frequencies closest to 60 Hz.

Summary of Issues – Question 6:

- The team should provide the technical justification for BES busses at 20 & 75 MVA criteria

  Response: The SDT has considered all industry input and has decided not to modify the requirement. Although there are differing views on the question of how small a generator must be before its tripping does not have a material impact on system or island frequency, the SDT has decided that it is sufficient to require the monitoring of V/Hz at generators consistent with the NERC Statement of Compliance Registry Criteria. The SDT believes that the requirement as written generally captures about 95 percent of utility-owned installed capacity, which the team believes is sufficient accuracy for assessments of UFLS programs. The SDT also has decided to modify Requirements R7.1 and R7.2 (now parts 4.1 and 4.2 of Requirement R4) to apply to the same generating units and plants.

- The v/Hz requirement does not belong in this standard ("load shedding document") – IEEE standards already exist to address v/Hz.

  Response: This requirement supports reliability and the majority of the commenters indicated their support. IEEE standards do not restrict V/Hz during UFLS events; they only establish generator protection guidelines. While it may be unusual for generators to trip on V/Hz protection during UFLS events, the risk is still present, and a region's UFLS program design should not cause excessive levels of V/Hz at or near significantly sized generators to the degree that may cause them to trip. Therefore, the SDT has retained this requirement.

20) Question 6:
In the first posting, the Characteristics of UFLS Regional Reliability Standards required that UFLS programs be designed to limit the potential for overexcitation (V/Hz) of power system equipment at all Bulk Electric System buses. Based on industry comments, the SDT has revised this requirement in the proposed continent-wide standard to apply only at generator buses and generator step-up transformer high-side buses associated with individual generating units greater than 20 MVA (gross nameplate rating) and generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) that are directly connected to the BES. The SDT believes this change better addresses the need to have UFLS programs designed to coordinate with protection that may trip generators during an underfrequency event. Do you agree with this change? No

21) Question 6 Comments:
Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit. It also seems this only applies when frequency drops below 57.2 Hz. This is discussed further in my comprehensive discussion included in item 8.

This requirement should not be included because this is not a major concern. Assuming we want to study this, we will find this cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation.

The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document. During an under frequency event, generators should be working to pull voltages down anyway.

Please see response to question 8 regarding overvoltages related to tripping load without tripping capacitors.

Summary of Issues – Question 8:

- Continent wide standard cannot provide "right" UFLS program for all areas

  Response: A continent-wide standard can provide appropriate reliability requirements for most areas since most areas already have programs in the 25-30 percent of load range. A regional variance may be proposed if a regional or sub-regional UFLS program substantially exceeding this range cannot be made to comply with the continent-wide performance characteristics. Input from MRO has been considered in replacing the discrete points in Draft #2 with curves in Draft #3. Please see R3 and Attachments 1 and 2.

- The continent wide standard should check if the assessment steps have been completed (a “pass/fail” approach)

  Response: The SDT believes that a check list approach constitutes a fill-in-the-blank standard similar to the existing PRC-006 which FERC did not approve. The SDT believes that a check list approach will not address the FERC concern that fill-in-the-blank standards have the potential to undermine uniformity. The SDT believes that requiring an assessment to show that compliance with certain measures of reliability (i.e., performance characteristics) has been achieved is necessary. The SDT does not believe that reliability can be assured if the standard is limited only to checking to see whether certain steps have been followed in conducting an UFLS assessment.

- The NERC regions have always had the organizational structure to bring all of these experts together, and I doubt the concept of having a group of Planning Coordinators will be as effective at getting the subject matter experts involved

  Response: In fulfilling the Planning Coordinator function the Planning Coordinators need to coordinate with the “experts” such as relay engineers, Transmission Planners, Distribution Providers among others. The Standard Drafting Team does not see an alternate approach to assigning responsibility to the Planning Coordinator. Furthermore, FERC Order 672 indicates that requirements should be assigned to users, owners, and operators of the bulk electric system and while the SDT agrees that the Regional Entities should be involved, the SDT can only assign the responsibility to the Planning Coordinator (a user, owner, operator). The SDT feels that it has not precluded the involvement of the Regional Entity in the process nor precluded the Planning Coordinator(s) from electing to use their regional standards development process as an open to all entities and inclusive process to establish the program.

- “Real world” factors also should be considered when designing the program – studies aren’t sufficient

  Response: The SDT agrees that real world factors should be considering when designing and assessing a UFLS program; however, the SDT believes the appropriate method for considering the factors is to model them in studies. The SDT is not aware how else the effects of such real world factors as variation in governing response and controls that override governing response can be evaluated.

- PRC-006 and PRC-024 are circumventing the needed analytical process and are drawing conclusions about what is appropriate before the study work is performed. These standards provide no technical justification for the proposed measures. As written, these standards will encourage smaller load shedding programs, and if that happens, the result will be that portions of the grid will have less of a safety net to rely upon when extreme events occur.

- Setting the performance characteristics before designing the programs is putting cart before the horse especially because size of the program should be a factor considered in determining any performance criteria

  Response: (to both comments immediately above): Clear and measurable reliability requirements need to be set. This goal cannot be accomplished if the reliability requirements are continually subject to being adjusted to accommodate study results. The SDT is confident that the draft UFLS standard will be found appropriate for the vast majority of North American systems. The fact remains that almost all existing North American UFLS programs fall within the 25-30 percent of load range. The SDT believes that what is behind the majority of the commenter’s comments is a concern over sub-regional UFLS programs that need to be substantially more than 25 percent. A regional variance may be proposed if a substantially larger sub-regional UFLS program cannot be made to comply with the continent-wide performance characteristics for load-generation imbalances up to 25 percent. Input from MRO has been considered in replacing the discrete points in Draft #2 with curves in Draft #3. Please see R3 and Attachments 1 and 2 in Draft #3.

- There is no requirement to assess load shedding needs – major topology changes should be considered when performing an assessment

  Response: The draft standard requires the identification of islands for study in Requirements R1 and R2 of Draft #3. This identification should consider topology changes. The study of such islands should reveal the load shedding needs in terms of percent of load to shed.

- Any party (utility, group, region, etc) should not be forced to shed more than the minimum called for in the Standard, but we should let them shed more load when there is an advantage to doing this

  Response: The SDT notes that the proposed standard does not specify the amount of load to be shed. Specifying such details of the programs is left to the Planning Coordinators in each region. The SDT agrees that entities should be allowed to shed more load than required when advantageous provided that shedding more load does not result in an

overfrequency condition that adversely impacts reliability.

- Both voltage and frequency are highly subjective and are not really a good way to indicate if a load shedding program is going to get the job done.

  Response: The SDT understands that frequency performance is subject to factors that are often uncertain or variable, such as aggregate inertia, aggregate governing response, turbine power versus frequency, and the effect of load shedding on system voltage and the secondary effect of that voltage on remaining load, etc. Nonetheless, a UFLS program must be set up to operate on frequency settings, generator off-nominal frequency durations defined in terms of frequency level must be respected, and system load is a function of only the voltage and frequency applied to it. The SDT believes that these quantities are the only quantities available for assessing the performance of an underfrequency load shedding and that the only means of evaluating these quantities is through dynamic simulations.

- The standard is driving towards lowest common denominator - Somewhere the NERC UFLS standards drafting team also concluded that "UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics". Programs which shed different amounts of load will inherently have different performance characteristics, and work over a different range of overloads. By setting frequency based performance criteria these two standards are definitely forcing things towards the lowest common denominator as the proposed "measures" can only be met by a smaller load shedding program.

  Response: The SDT disagrees that the draft standard would result in least common denominator reliability. Again, the SDT has determined that the approach that is least intrusive on the flexibility to set UFLS design parameters within a region, but that addresses the need for inter-regional coordination, is to establish continent-wide performance characteristics as are now in the draft standard. The draft standard would not restrict regions from having programs larger than 25-30 percent of load because such programs are not precluded by the proposed standard, and a regional variance may be proposed should such larger programs encounter difficulties in complying with the performance characteristics up to the 25 percent load-generation imbalance level.

- This reliability standard writing process should not replace engineering judgment

  Response: Reliability standards must establish clear and measurable requirements. The SDT does not intend to preclude use of engineering judgment in meeting the requirements; however, engineering judgment cannot be a substitute for clear and measurable requirements. The SDT believes a balance has been achieved in the proposed standard between imposing clear and measurable continent-wide requirements versus permitting flexibility for engineering judgment within each region.

- I think it makes perfect sense to "measure" if we are fulfilling the basic aspects of load shedding obligations. The "measure" would be "have you done activities x, y, z?". Instead we would focus on the big picture, which is to make sure we have a reasonably effective safety net in place. The "measures" could become simple pass/fail checks to see if we have covered the basics of implementing an appropriate UFLS program. I suggest that we keep it really simple. It will be easy to check on things like: 1) has an appropriate program been designed which satisfies a checklist of items that have to be considered such as coordination with generation protection, 2) has the program been implemented, 3) has the program been periodically reviewed, 4) have any changes that came about from the review processes been implemented in a timely fashion, and so forth

  Response: The SDT believes that a check list approach constitutes a fill-in-the-blank standard similar to the existing PRC-006 which FERC did not approve. The SDT believes that a check list approach will not address the FERC concern that fill-in-the-blank standards have the potential to undermine uniformity. The SDT believes that requiring an assessment to show that compliance with certain measures of reliability (i.e., performance characteristics) has been achieved is also necessary. The SDT does not believe that reliability can be assured if the standard is limited only to checking to see whether certain steps have been followed in conducting an UFLS assessment.

- R1- a group of planning coordinators is not going to be the equivalent of the type of broad based participation we have historically achieved through the NERC Regional via the existing committee structure.

  Response: In fulfilling the Planning Coordinator function the Planning Coordinators need to coordinate with the "experts" such as relay engineers, Transmission Planners, Distribution Providers among others. The Standard Drafting Team does not see an alternate approach to assigning responsibility to the Planning Coordinator. Furthermore, FERC Order 672 indicates that requirements should be assigned to users, owners, operators of the bulk electric system and while the drafting team agrees that the Regional Entities should be involved, the drafting team assigned the

responsibility to the Planning Coordinator (a user, owner, operator). The drafting team feels that it has not precluded the involvement of the Regional Entity in the process nor precluded the Planning Coordinator(s) from electing to use their regional standards development process as an open to all entities and inclusive process to establish the program.

- R2-stresses consistent application across the region, and I would argue that only the final analysis of the system will tell you if this makes sense. There may be subregions which have different needs. In MRO, the Canadian systems have different needs than the US portion of MRO.

  Response: The SDT agrees that sub-regions within a region may have specific needs and has deleted the word "consistent" from this requirement to allow unique UFLS program parameters for a sub-region as part of the program developed by the Planning Coordinators within a region. However, if that sub-region is identified as being part of any other island that forms the basis for the UFLS program design (now Requirement R2), then the sub-regional UFLS program parameters must be coordinated with UFLS program parameters established for the remainder of the region to ensure the performance characteristics are met for all islands. A regional variance may be proposed if a sub-regional UFLS program cannot be made to comply with the continent-wide performance characteristics but support the reliability intent in an alternate fashion. Input from MRO has been considered in replacing the discrete points in Draft #2 with curves in Draft #3. Please see R3 and Attachments 1 and 2 in Draft #3.

- R3- this says we need criteria on how to select islands. It strikes me as odd that we need "criteria" on how to reach a conclusion. Shouldn't this just say that analysis shall consider possible system break up patterns that may form islands?

  Response: "Shall consider" is not definitive enough language to measure compliance against; "…shall develop criteria…" is definitive. In some regions, there may not be any "break up patterns." Thus, it is necessary to have some selection criteria as the requirement to identify islands that will be used to design the UFLS program.

- R4-I agree that coordination with neighboring regions is required, but I do not know how to resolve differences of opinion between regions. Are we trying to reach a consensus between regions, or just trying to share information and to create a forum for discussion? Obviously where breakups cause islands that straddle different NERC regions, we need to jointly evaluate that island. Even if this coordination is only to share information, it still allows everyone to learn from each other and is going to be quite valuable.

  Response: Thank you for your comment. Please see Question 6 on the comment form. R4 has been removed and a new Requirement, R4, has been added. We expect that a process for resolving differences of opinion between the Planning Coordinators will be necessary because their compliance with R4 will depend on it.

- R5 - Propose a wording change, I would rather say something like: "…shall identify islanding patterns that can be used as a basis for designing an UFLS program. This shall consider:" R5-is about identifying islands. I think it is the exact wording of this section that bothers me although I agree with the intent. I prefer to focus on break points that may lead to islands.

  Response: The SDT believes the language of the standard provides a clear requirement against which compliance can be measured; seeing the commenter agrees with its intent, no changes have been made.

- R7-is about the need to do periodic assessments. I agree we need a periodic assessment of some sort. Full blown studies on the other hand are seldom required unless some inherent flaw in an existing program is identified and we need to start with a fresh look at everything. I do not agree with meeting the performance characteristics in R6. We should meet performance characteristics which are defined as a result of the load shedding study process, and not just something that is tossed out up front.

  Response: The standard requires dynamic simulations to back up the required periodic UFLS assessments. The SDT has confidence that any inherent flaws in an existing program are more likely to be discovered in this manner than by any other approach. Reliability requirements should not continually be subject to being modified to accommodate study results.

- I think there are other ways to assess the risk of having units trip off early than just running simulations. This almost implies we have to use full stability cases as our only analytical method. Let engineers figure out how to study the problems using whatever tools, methods, and calculations they feel are appropriate.

  Response: The standard requires dynamic simulations in the assessments because the reliability risk of early tripping units can be adequately assessed in this manner. The SDT is not confident that analytical methods that do not involve

dynamic simulations can do this.

- If we require some assessment of load shedding “need”, then generation which drops off early can be evaluated in terms of how it affects the “needs” assessment, or we can demonstrate how loss of such generation affects programs in a general sense.

  Response: The SDT agrees. Load shedding needs should become apparent during the course of performing dynamic simulations for the assessment of island(s) identified in R5 (now R2).

- R-8 shouldn’t this database/modeling type of information be compiled as part of the regional model building process? NERC regions do this type of thing today, why is this group of Planning Coordinators getting involved in this. We use the NERC regions to do our coordinating activities, so why depart from what works? I need to understand the reasoning behind this before I can comment further.

  Response: At this point, UFLS data is not required to be included in regional and ERAG / MMWG model building. UFLS data is for a specialized field of study distinct from the general dynamic simulation data collected under MOD-012.

- R-9 appears to say that everyone shall trip load in accordance with the UFLS program. I agree with the intent.

  Response: Thank you for your support.

22) Question 8 Comments:

1.0 Introduction

After reviewing PRC-006 and PRC-024, I have to conclude that both are unsound. The general approach of trying to define a performance envelope up front before tradeoffs can be evaluated in the design work is going to be a problem. These standards really do not encourage the right thing, which is to ensure we have the right UFLS program in place to meet the needs of a given area. The “measures” are inherently subjective, and really do not measure if we have created the right “safety net”. I go into considerable detail to explain my concerns, but basically in the design phase we need to make compromises between mutually exclusive objectives. Therefore we need to stay away from trying to micromanage the design process at the Standards level. Tradeoffs affecting performance will always be involved and I do not think the standard needs to get involved in exactly how we reach a conclusion about what needs to be done. I think the standard should just focus on making sure we put the plans into effect, and that we implement the load shedding program. We should leave all of the performance issues to a work group that does the actual design and analysis. This is basically operating study type of work to create a remedial action scheme which responds to abnormal system conditions. My conclusion is that we need a different type of “measure” for the UFLS standard and that the generation off-nominal frequency protection related criteria in PRC-024 should be eliminated completely and that it should not be part of any NERC standard. PRC-024 is trying to make the compromise about what is an acceptable tradeoff for setting generation off-nominal frequency protection before the required study work is even started. It makes more sense to have a “measure” for UFLS which focuses on fulfilling the various activities such as design, implementation, and review, as the end result is what is important to ensure reliability. I envision this would be more of a pass/fail, have you performed these activities or not, type of assessment. I know this is a controversial statement, but I believe the following discussion will explain how I arrived at this conclusion.

1.1 My UFLS background

Before I comment on technical issues, I would like to provide background information. This is to explain why I hold such strong opinions on the subject of UFLS, and to show my involvement and commitment to developing appropriate regional UFLS programs. I hope this gives some credibility to my statements. I have a unique “hands on” work experience. This gives me considerable insight into this subject and a different perspective. I have about 20 years of experience with UFLS issues, have dug deep into the subject, have read all the technical materials I could find, and so forth. I spent several man years on this subject although my primary job function involves power system analysis, mostly operating studies (power flow and stability studies and so forth). My initial involvement in UFLS was an offshoot of disturbance analysis. This involvement with UFLS expanded into the area of assessing regional needs and in doing the technical work to develop a new UFLS program from the ground up which better fit the needs of different geographic regions. This was the big picture type of work with lots of things to consider. My background which is relevant to this area of investigation includes:

* 29 years of experience doing system studies (power flow, transient stability, operating study work, modeling issues, disturbance analysis, etc.)

* From 1987 to 1990 worked almost full time on the Colorado/Wyoming Off-Nominal Frequency Program design and study report (a regional load shedding and generation off-nominal frequency protection coordination effort tailored to the needs of the area, and which coordinated the needs to two islands, one a subset of the other). I was chairman of one of two technical work

groups created by the executive committee, and did a significant amount of the analytical work and report writing.

* 1996-1997, I worked on the WSCC UFLS program design and study report as one of five authors. This program is presently the WECC program and was strongly influenced by how the Colorado/Wyoming program was developed.

* 2001, I performed a review of the MAPP UFLS program on behalf of MAPP, and concluded that MAPP needed to develop a new UFLS program to address overfrequency and generation off-nominal frequency protection concerns.

* 2006-2007, I was chairman of the MRO UFLS Task Force which designed a new UFLS program and generation off-nominal frequency protection requirement for MRO. This was basically the follow up to the MAPP work that stalled out in 2001. Implementation has been put on hold until the NERC UFLS standards writing process has concluded.

* I have had the benefit of collaborating with many other engineers, of varied backgrounds, on the subject of UFLS. I have been exposed to many different aspects of the problem and to different viewpoints. My perspective is based on information I have gathered as it pertains to system planning and operation, relaying, control area type of issues, power plant issues, and so forth.

I was once told that "sometimes things seem simple only because we don't usually have the time to learn the complexities". This is certainly true of UFLS issues. This standards drafting process has led to certain initial conclusions that set the direction of how the UFLS standard is being drafted. I have to point out that things are not nearly as simple as they may appear at first glance, and we are jumping to the wrong conclusions, and that is steering this process in the wrong direction. In order to best explain my concerns with how this UFLS standard is being written, I need to cover some of the basics to provide a context.

1.2 The big picture: what are we trying to accomplish by shedding load?

The simple answer is we want to use load shedding as a safety net. The objective is to prevent a blackout following an islanding event that creates an imbalance between load and generation. We want the program to force quick frequency recovery so that we can better coordinate with generation off-nominal frequency needs. We want to make sure that our program has no fatal flaws that are going to make things worse, and hopefully we can try to make this program as robust and foolproof as possible.

1.3 Who should design UFLS?

The design details need to be resolved through a technical study process involving individuals with the skills to do this type of analysis, or who are willing to spend considerable time to learn the skills. Historically this has been accomplished by forming appropriate study groups. Such groups usually include individuals with varied backgrounds which may be relevant to dealing with the different aspects of off-nominal frequency issues. The NERC regions have always had the organizational structure to bring all of these experts together, and I doubt the concept of having a group of Planning Coordinators will be as effective at getting the subject matter experts involved.

1.4 Analytical approaches and modeling limitations

First of all, there is no perfect tool for studying load shedding and performance is highly subjective. The question is, what performance, and for what conditions and assumptions? We have to keep this in mind before jumping to conclusions about what kind of performance characteristic we can meet.

Trying to establish the UFLS performance characteristic up front and then designing the rest of the UFLS program afterwards is equivalent to saying we know what our protection needs are and what the resulting system performance is going to look like before we do any kind of analysis at all. This is unrealistic. The one factor which is the most significant is the size of the UFLS program. Larger programs have inherently different performance characteristics than small programs. More compromises have to be accepted to make larger programs work. NERC Regions typically set a minimum criteria for load shedding, but higher levels are sometimes needed and are typically allowed. The amount of load presently being shed in different areas varies from about 25% to 60% or more.

Modeling must involve some form of dynamic simulation which captures the salient features. Underfrequency relay application guides suggest use of a simple equivalent inertia model which captures frequency decay dynamics. I have found this approach extremely useful and insightful. This approach is good for rapid prototyping and generalizing trends, evaluating performance over a range of overloads, evaluating sensitivities, etc. The weakness of this approach is it does not include effects of voltage changes and usually ignores governor action (in MRO UFLS work, we added a governor model as part of the sensitivity work, but designed the program to work even if we get no net governor type of response to an underfrequency event). The “Equivalent Inertia” approach is essentially use of a one bus stability case with voltage held at unity, which models the inertial response of a full system.

Full stability cases are more useful for looking at a very specific scenario (one overload level, a historical event, etc.). Stability cases are also useful in addressing voltage transients and identifying possible system break points. The usefulness of a full stability case for the study of load shedding is often overestimated. In reality, too much detail is not always helpful in sorting out the general trends. Stability cases give a very specific answer but can fail to give the needed insight about how things work "in general" and it can take significant time to modify cases so they are useful for this type of analysis. The level of modeling needed for typical transient stability studies is somewhat different than what might be needed for a load shedding study, so do not expect that stability cases will have all of the modeling details needed for load shedding studies.

The user has to be aware of what each dynamic modeling approach represents, and what the modeling limitations are. Even full stability cases do not model some of the processes which have an effect on a load shedding event and consequently results have to be carefully interpreted (for example, stability cases do not model generating plant boiler dynamics and emergency overspeed controls which protect for full load rejection, but which operate on large partial overloads). The way islands are created in the simulation can affect results. For instance, opening all lines at the same instant to form an island is a typical modeling approach that has nothing to do with how islands really form. This approach to creating an island will affect the final result to some extent, but we generally have no better option.

We also need to stop once and a while and consider the real world issues to try and make things as fail safe as possible. There is more to UFLS design than just running studies.

The point is that study work results are inherently approximate, and much more subjective than most realize. Simulations need to be interpreted with a good deal of common sense and a good understanding of system dynamics, and a clear idea of what all the qualifying simulation assumptions are. Hopefully this standard will stay away from prescribing any particular modeling or analytical approach. Let planners use the engineering tools they have as they see fit, and let them decide on the tradeoffs we have to accept to make this work.

1.5 UFLS design work, conflicting requirements, and uncertainty

UFLS program design and performance details can only be worked out through a systematic study work process that considers all of the relevant details, the conflicting requirements, and as much of the inherent uncertainty involved as is possible to consider. Despite the complexity, I believe we can design a good UFLS program for a given region if we are systematic and try to deal with all the issues as best as possible by applying good engineering methods and good judgment. Once we lay out all the details, we have an optimization problem, and have to consider the options available and the tradeoffs. Some of the final program details will probably end up being decided according to a judgment call. However, I do not believe that we can set performance standards first and then expect the engineers to magically make this work. Almost everything to do with UFLS has to be based upon study work and must have a solid technical justification.

The design goal is to develop an UFLS program which has a high probability of preventing system collapse following an islanding event. This sounds simple so far, but a little investigation will show the problem we are trying to deal with is complex and poorly defined. We are guessing at what might happen and are trying to hedge our bets in the face of considerable uncertainty. The deeper the investigation goes, the more we become aware of the conflicting requirements. For instance, the things we need to do to limit the minimum frequency, to limit the maximum frequency, to ensure good relay coordination, and to maximize the size of the UFLS program all conflict with each other…to solve one problem we impact a different objective.

Many factors which affect real world performance are outside of the control of the parties doing load shedding. These factors are: dynamic characteristics of load, system energy stored in rotating generation via the flywheel effect (this is the inertia, and it relates to dispatch), units which are unresponsive to governor action, boiler dynamics, power-load controllers which can over power governors and force units back to the original schedule, gas turbines which inherently drop power as frequency drops, wind generation which essentially provides no inertia and is highly unpredictable, unexpected random events, etc. To complicate the analysis, different parts of North America will have to address factors that are unique to their own local areas.

We want to keep "real world" complications in mind as we do our studies, and it is even reasonable to anticipate what system operators will have to do next if load shedding fails to work as desired. Historical events show this happens, and if we are lucky frequencies will stall out close enough to 60 Hz that operator action can be initiated to restore frequency (this has implications concerning why it is a really bad idea to set generation protection time delays too short for frequencies between 59 Hz and 61 Hz).

Also consider that we are just making educated guesses about what islands may form in real life. Some islands are easy to identify and predictable, but that is not always the case. Major breakups seem to occur following a sequence of events which are far beyond anything covered by typical criteria, and these events are usually nothing we would have ever dreamed up. Often the final island is not what we anticipated.

At this point let's assume we know what our island should be, what the maximum overload for this island will be, and that we

have some idea of general performance objectives. As we go into study mode we find that many of the factors which affect results are difficult to pin down. This includes the assumptions used for load damping, governor response, and the energy stored in rotating units (the inertia). The term “typical data” reflects a rather wide range of these parameters. In developing the MRO program we dealt with this uncertainty by using the simplified equivalent inertia model and then varying all of these parameters over a fairly wide range as we also considered a range of potential overloads. This is much more than is typically done, and this type of sensitivity analysis would have been extremely difficult, if not impossible, to perform with a full stability case.

In the design phase we want to work though all of the interrelated issues, such as achieving coordination with generation off-nominal frequency protection. To do this right, we have to design a load shedding program which gives the best frequency recovery (subject to all the other constraints), and then see how much time is spent below 60 Hz in various frequency bands so that we can propose generation protection settings with delays with some margin over our worst case frequency recovery times. We also need to know something about actual generation off-nominal frequency capabilities to further judge the appropriateness of the suggested protection settings.

We want to make sure this safety net is well designed and that it has no obvious flaws. Preferably, we want to anticipate what could go wrong so that we can try to avoid as many problems as possible and alter the design accordingly. Then work has to iterate towards a best compromise solution.

2.0 Critique of PRC-006

Although the intent of this write up is to discuss PRC-006, I also have to discuss PRC-024 in some detail since both standards go hand in hand. Load shedding and generation protection are interrelated. Both parts have to be addressed together in any discussion of UFLS issues. It is unfortunate the standards drafting teams broke things down into two different standards like this. Generation off-nominal frequency protection is inherently part of UFLS programs, and has to be assessed in this context.

2.1 UFLS standards need to be technically sound.

I empathize with the standards drafting team and know the difficulty of their task better than most. However, I am not satisfied with the NERC UFLS standard PRC-006 or the generation protection settings suggested in PRC-024. I find this new PRC-006 UFLS standard and the companion PRC-024 generator off-nominal frequency standard to be unsound. These standards are circumventing the needed analytical process and are drawing conclusions about what is appropriate before the study work is performed. These standards provide no technical justification for the proposed measures. As written, these standards will encourage smaller load shedding programs, and if that happens, the result will be that portions of the grid will have less of a safety net to rely upon when extreme events occur.

2.2 There is no requirement to assess load shedding needs

My observation is that a minimum load shedding requirement of 25% to 30% of system load will serve the needs of most of the system. That is my personal judgment, based on previous study work experience. I also know we can design fairly well behaved programs which shed 30% of load, and my personal bias is to shed more than to shed less. However the 25% load shedding used in the East was based on the same type of analytical process as I would go through, and they felt this level was a better fit for the tradeoffs involved. UFLS design involves these types of judgment calls. However, it seems odd that this standard does not require any kind of assessment to define the size of the imbalance we may have to deal with. This means we are not requiring anyone to know their actual load shedding needs. Perhaps that is implied by having “groups” do the UFLS study work. The load shedding needs are the first thing I would want to know, and to get at this information we have to evaluate possible system breakup patterns and possible load and generation scenarios to see what the imbalance might be. The purpose of such a review would be to see how much coverage the 25% load shedding requirement gives, and to estimate what might be a more appropriate load shedding target level. This type of analysis does not have to be perfect; we just need to know general magnitudes and make sure the involved parties feel their own needs are being satisfied. I use the phrase “target level” in the sense that once study work is performed we may have to consider a different size load shedding program to achieve over all coordination requirements. Everything is a series of tradeoffs. If we set performance criteria too tight, we could easily find that all we have left to work with to meet the criteria is to put in a smaller program, and then we will only meet criteria over this smaller range of coverage.

2.3 Higher load shedding levels should be encouraged if it makes sense

While we do not believe that any party (utility, group, region, etc) should be forced to shed more than the minimum called for in the Standard, we believe we should let them shed more load when there is an advantage to doing this. This will be the exception, but some areas, such as parts of Canada, are obviously prone to islanding and these areas often have high load shedding needs. Some areas shed 60% of system load, or perhaps more. Historically, UFLS standards have been minimum standards which tell utilities they must shed at least a certain amount of load. Regional programs allowed or even encouraged utilities to shed more load when it made sense. It seems obvious that this intent is still there, but the problem is that the “measures” chosen for this standard actually discourage this.

2.4 Frequency is subjective, and should not be a “compliance measure”

PRC-006 uses frequency and voltage as “measures” to ensure UFLS programs satisfy reliability objectives. I believe these are both inappropriate “measures”. Both voltage and frequency are highly subjective and are not really a good way to indicate if a load shedding program is going to get the job done.

Let’s review the basics: 1) frequency drops following loss of generation or import with an initial rate of change of frequency defined by the size of the overload and the system inertia, 2) since turbine power can generally be assumed to be constant, this frequency drop increases generator torque as torque=power/speed, 3) load torque drops according to the load damping characteristic, and 4) we eventually reach equilibrium at a new lower frequency where once again Generation = Load at the new synchronous frequency. (A footnote: turbine power is not always constant during a frequency decline, combustion turbines have thermal limits requiring the power output to be lowered as frequency drops, causing a further drop in system frequency. Governor response on these units will only be momentary before thermal controls take over.)

Now let’s consider how these variables affect our performance “measures”. For a given overload, final frequency is a direct function of the load dynamic characteristics which are not precisely known. We know the damping constant used in models is in the range of 1 to 2, and anything in that range is “typical”. Low damping will give the lowest frequency and highest frequency deviations. The equivalent system based inertia H = sum of MW-sec of online units/total Pgen, is a function of different unit dispatch scenarios. For a given overload, high inertia gives slower rates of frequency change, better relay coordination, a higher minimum frequency, and slower frequency recovery. Small inertia gives high rates of frequency change, lower minimum frequencies, relay coordination problems and possible overshedding.

With the wide range of “valid assumptions” to choose from, folks can essentially pick the off-nominal frequency results they want to show for compliance purposes, and if results of a large program don’t look good enough, they can switch to a smaller program so that it satisfies the “measure”. Choosing modeling assumptions is not “gaming”, it is standard engineering practice, but a single set of assumptions does not tell the full story. I would rather have measures which encourage folks to look for potential problems instead of measures which punish them for finding such problems. I would also like to see the measures encourage larger UFLS programs when that meets some identified need.

To further complicate matters; let’s compare a large UFLS program (sheds 45% to 60% or so) with a small program (sheds 25% of load). Let’s assume they both have 5 stages of load shedding. Over the range covered by the small program, it will work in a more refined manner than the larger program as it uses smaller load blocks. For overloads between the sizes of the two programs, only the larger program will work. So how should performance be judged?

There is a reason I chose the same number of load shedding blocks in this example, and it is worth digressing for a moment to explain. As a practical matter, UFLS programs can only make use of 5 or 6 high speed load shedding blocks while still achieving good relay coordination and while also keeping the minimum frequency from dropping too low. This is not a hard and fast rule, but it is what I have seen in my study work. This is an effect related to inherent time delays introduced by relaying detection times and breaker operating times, and the frequency spacing needed between relays to achieve relay coordination. Of course if we are willing to toss out relay coordination we can improve the underfrequency response at the expense of creating overfrequency problems which then have to be hammered back by automatic load restoration or the equivalent (for instance, Manitoba Hydro can drop power coming in on DC lines to balance load with generation but that is a very unique situation).

2.5 Voltage is subjective, and should not be a “compliance measure”

Overall, I am more concerned with the magnitude of the voltage out at the load rather than volts/Hz issues at the generator. The volts/Hz issues are already well covered by IEEE/ANSI standards, and this is difficult to model since exciter/voltage regulator models typically do not include a volts/Hz function, so the automatic reduction of the generator terminal voltage which occurs in real life does not show up in simulations. During load shedding the generators will be pulling the voltage down anyway. My understanding is that volts/Hz issues are less restrictive than other underfrequency concerns/factors. This would be something we need to look at if we allow frequencies to drop to 57 Hz or less. (Unit terminal voltage is controlled by the voltage regulator and outside of the transient time frame, we can assume the steady state voltage will be limited to 1.05 pu to .95 pu, so 1.10 v/Hz gives problems in the range of 60*1.05/1.1=57.27 Hz to 60*.95/1.1=51.8 Hz.) In addition, units are only at risk if this voltage regulator function fails, or if units are in manual voltage control. In that case the backup volts/Hz relaying will trip a unit. I am not too worried about voltage regulators failing and do not consider volts/Hz as a major risk factor. Usually volts/Hz is not given too much attention when designing UFLS programs. I am not aware of any of the existing UFLS standards having any volts/Hz criteria, but perhaps I am mistaken. I suggest the volts/Hz requirement be removed from PRC-006 because it really does not add anything which is not already covered elsewhere.

2.6 Overvoltage as a source of additional uncertainty

As load is shed we can get overvoltages out at the load which effectively increases system load. To some extent this voltage

related load increase offsets the benefit of load shedding. Voltage control issues during load shedding/system break up are extremely difficult to assess. Voltage changes are a function of changes to VAR supply/consumption, as well as inversely proportional to system strength (i.e. fault MVA magnitude). System breakups and associated loss of generation can weaken the system and make voltage control much more difficult to manage. There is a general recognition that some capacitors need to be shed with load, but such details have to be worked out and refined at the local utility level as part of the load shedding implementation phase. I do not have a good idea of what is “the best that we can do”. I imagine it will vary with disturbance. I am not sure how this should be handled in the standards drafting process. I want to create an awareness of the problem so that folks give this some attention, and apply good common sense, but I do not want to turn this into any kind of “measure”. This is more of a bottom up type of analysis where very specific local detail has to be considered, where the rest of the UFLS conceptual work is the top down, big picture stuff where we do not need to address such specific local details. I am confident that utilities will do the right thing once set on the right course, and these types of details can be reviewed in the subsequent periodic UFLS assessments and things tweaked if needed. I just don’t know how to make this process any better than this. We have to be careful that we do not try to micromanage this difficult task.

The MRO UFLS effort tried to anticipate as much complication as possible, but we could not cover all of the inherent uncertainty involved. No one could. The main source of uncertainty we could not deal with is how potential overvoltage’s may increase load and decrease the effectiveness of the load shedding program. This gave us additional justification for using a "no net governor response" scenario for evaluating coordination between load shedding and generator protection (this voltage uncertainty is not the only reason for using a no governor assumption: basically units that are base loaded cannot respond to underfrequency, power/load controllers may override governor action after a short time delay, combustion turbine thermal limits will quickly override their governor action with power dropping off faster than the frequency decline, wind generation may drop off and would not have a governor anyway, and so forth; the bottom line is that we do not know what level of net governor type of action we can count on, and what little we get may be offset by increases in voltage).

2.7 PRC-006 and PRC-024 are forcing UFLS programs to the least common denominator

PRC-024 and PRC-006 both fail to satisfy a comment made in the NERC UFLS unofficial comment form which indicates the UFLS standard is supposed to provide an appropriate level of reliability, not the least common denominator. Somewhere the NERC UFLS standards drafting team also concluded that “UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics”. Programs which shed different amounts of load will inherently have different performance characteristics, and work over a different range of overloads. By setting frequency based performance criteria these two standards are definitely forcing things towards the lowest common denominator as the proposed “measures” can only be met by a smaller load shedding program. The PRC-006 UFLS standard and companion PRC-024 establish tightly defined performance characteristics which at best will just barely work for a 30% load shedding level. Perhaps I should be more careful and say it works for a 30% load shedding level for a range of assumptions, but not for all of the conditions/modeling assumptions that we looked at in the MRO study. Those settings certainly do not encourage a robust UFLS program.

This “one size fits all performance envelope” approach only works if we use the worst case (largest UFLS program) as a basis for the performance envelope. We can characterize these larger load shedding programs as having to accept more tradeoffs. The minimum frequency will be lower, the maximum frequency will be higher, larger load blocks will have to be shed making things more drastic, and the programs are likely to be more susceptible to relay coordination problems (due to the high rates of frequency decline associated with the large imbalances). What you get for these tradeoffs is a bigger safety net.

The generation coordination part of UFLS analysis should be addressed directly in PRC-006 as something that needs attention, but the specific details such as those presented in PRC-024 need to be worked out at the UFLS working group level in coordination with the study process that designs the load shedding program. This type of information is not appropriate for NERC standards. The off-nominal frequency limits in PRC-024 should never have been created and should be eliminated. PRC-024 is poorly thought out and is going to do much more harm than good.

Setting generation protection up front before casework is run is putting the cart before the horse. This is an attempt to micromanage the UFLS analytical process without having a full view of the big picture. It just represents someone’s judgment call concerning what is appropriate. It does not accurately reflect generation capabilities and no technical basis was provided to justify the “measures” in the standard. In my opinion PRC-024 is seriously flawed and actually is a serious threat to reliability. It also conflicts with the new MRO UFLS program we developed, and if other regions did the type of analysis that we did, they would probably find this causes problems for them as well. (Most UFLS programs do not go to as great of lengths as we did to look for potential problems over the full range of overloads covered by the program.)

I am well aware of generation off-nominal frequency issues and concerns, I have had my eye on this for 20 years. In the MRO UFLS study we did all that we could to minimize the off-nominal frequency exposure to generation, even going to the point of designing the load shedding program as the first line of defense for generation. This is achieved by designing the UFLS program to force quick frequency recovery even if we get no net governor action. This is achieved by having small blocks of load shed on delay that only trip if frequency recovery is sluggish. The point to make here is that the PRC-024 standards drafting group is not

the appropriate group to be deciding on what tradeoffs are appropriate for coordinating load shedding with generation protection requirements, and they are ignoring some important “real world” consequences. Some of what is in PRC-024, if implemented, would be catastrophic for the grid.

2.8 Overfrequency issues

The diagram from PRC-024-1 suggests that overfrequency tripping of generation is going to be allowed in similar fashion to how underfrequency tripping of generation is applied. Extreme caution is needed. If we add relays to instantly trip generation according to the overfrequency part of PRC-024, we will have multiple units tripping at the same time and we will cause a blackout. I would call this a really big fatal flaw.

Units self protect on overspeed and we do not have to add additional overfrequency tripping relays unless this is a planned activity used to balance load and generation.

It is important to have some understanding of overspeed issues and related controls, so I need to take a moment to cover this subject. In addition to the normal speed regulating governor, all power plants already have internal emergency overspeed controls to deal with full load rejection (loss of all lines out of the plant with turbine running flat out). These controls also activate on partial load rejections (overfrequency during islanding). These controls can have many names: emergency or preemergency governor, overspeed controls, load rejection controls, trip anticipators, or something similar. We do not want to be modifying these controls and their settings, but we need to understand how they operate. These controls vary at each plant so the following discussion has to use generalities to make my point. I am most familiar with controls on steam plants so this discussion applies to that type of generation. Generally these emergency overspeed controls try to limit peak speed to something below 110% by closing all turbine valves, and if this fails, the unit is tripped to prevent mechanical damage. To limit peak speed, these controls have to start closing valves as units start to accelerate. These controls are applied a little differently at every plant, but have to act before things get out of control, so they generally activate between 61.2 Hz to 61.4 Hz on low inertia units (in this instance I am talking of the inertia constant in dynamics, H=MW-sec/Mbase of machine), and sometimes not until 62 Hz if unit inertia is high. These emergency overspeed controls are in addition to the normal governor, and are much more drastic and just slam all steam valves shut. These emergency overspeed controls are not modeled in stability cases and I bet that most planning engineers have never given them much thought. It seems we never see frequencies any higher than about 61.4 Hz following a breakup, while stability cases might indicate frequency should have gone much higher. These would be the controls responsible for that disconnect between the real world and the simulation world.

Outside of the inherent factory installed overspeed controls, we have to exercise great care and caution when applying additional relays to trip generation on overspeed. The purpose of such tripping would be to restore the balance between load and generation within an island. If this is done, we need to be aware of the risk involved. Because these load rejection controls slam valves shut, the system frequency is unlikely to get much higher than 61.4 Hz (for a system which is primarily coal fired) no matter how large the initial imbalance. (Most steam units that I have looked at activate around 61.2 Hz to 61.4 Hz, and at one time I looked at every unit in Colorado and Wyoming to get a feel for what is typical.) Once these controls activate, frequency is no longer a measure of the imbalance between load and generation. We cannot keep steam valves closed for too long, constraining all the steam with the boiler going full tilt, or else random unit trips will start to occur due to any number of internal plant problems. We do not know how much time we have to get valves back open before we are at risk of losing a unit. Someone estimated 15 seconds (I can’t say if this is right or wrong, but it sounds about right to me), and then internal plant problems will start to occur. Often we see that one plant trips first and this helps. That reduction in generation rebalances things for other units allowing steam valves to reopen. The random nature of what happens in response to overfrequency complicates any planned unit tripping actions to correct the imbalance. If the sum of planned and unplanned tripping is too much, we cycle into another underfrequency event. This illustrates why dedicated unit tripping on overspeed has to be considered carefully, and should only be applied as a method to rebalance load and generation, and not as overfrequency protection of the type we apply for underfrequency. If generation is tripped to correct overspeed in an island, it has to be done in small increments (equivalent to about 1 to 1.5 % of remaining load) and trip times have to be staggered. For the purpose of balancing generation with load, unit tripping should only be implemented on a few selected small units. The trip setting would have to set at frequencies no higher than something like 61Hz to 61.4 Hz, or else these relays may never pick up. Picking the right delay times is tricky and would have to be based on simulation results. In practice, it may make more sense to do automatic load restoration to rebalance. This is something that has to be studied on a case-by-case basis.

As a side note: in the MRO UFLS effort completed in 2007, we were very concerned about overfrequency. This led to changes from the MAPP program of shedding 3 blocks of 10% to a program shedding 5 blocks of 6% . We then focused on adding adequate spacing between relay settings to reduce the risk of overshedding under our worst case assumptions of large overload, low inertia, and low load damping. The compromise was we had to accept lower minimum frequencies.

2.9 We need realistic minimum frequency limits on generation that meet load shedding needs

I also have concerns with the chosen minimum frequency in PRC-024, and the time delays proposed at different frequencies.

Although the MRO UFLS Taskforce expects that under "typical conditions" that minimum frequency will be above 58 Hz, (for loss of generation/import of up to 30% of system load in the island), our worst case simulations indicate we could briefly dip below that, and we used our worst case results to set generation protection frequency settings and delays. In addition, our "equivalent inertia" modeling approach ignores machine to machine oscillations which might cause frequency at different locations to differ by .2 Hz or so as the system frequency rings down. For this reason, we chose 57.6 Hz as the point where instant tripping of generation is allowed. This is below our worst-case minimum frequency of 57.77 Hz (for a very low inertia, low damping, no governor scenario that is perhaps overly pessimistic). This instant trip setting for generation can also be justified in another way. Our design criteria set a target where we wanted the minimum average system frequency >= 58 Hz, and we seem to meet this for most conditions. This 58 Hz minimum frequency seen in our models then has to be adjusted by about - .2 Hz to account for machine to machine oscillations seen in the real system and not in our model, plus about .2 Hz margin to ensure good relay coordination. This takes us back to 57.6 Hz as the appropriate frequency for the instant trip setting on generator off-nominal frequency protection. Programs which shed more than 30% of load will need to relax generation protection and accept lower frequencies and longer time delays.

2.10 An example of coordination between load shedding and generation protection as performed in MRO UFLS study

In order to come up with the MRO generation protection settings we monitored time spent in frequency bands spaced .1 Hz apart and we consider the performance over the full range of coverage (0 to 30 % loss of generation) and considered a wide range of assumptions concerning system based inertia (H system base = total MW-sec stored in rotating mass divided by P gen) and a range of damping, in addition to a possible range of governor actions. We optimized the program to minimize time spent below 60 Hz while addressing all the other constraints we had to deal with. Once we knew the expected worst case times in each .1 Hz band below 60 Hz for the optimized program, we came up with the stair step type of generation frequency versus time delay settings that gave a reasonable fit to the expected worst-case time versus frequency information (plus some margin) with the fewest frequency bands. To fully understand what we did you will have to refer to the MRO UFLS report on the MRO website. The short version is that we ran 1000's of cases to arrive at our conclusions. What we came up with for generator underfrequency protection minimum time delays is what we need to ensure the load shedding has time to play out to restore frequency and to give some margin to ensure relay coordination. If we shorten the generation protection time delays and raise the frequency setting for the instant trip point, then there is a narrower range of conditions for which the UFLS program would be expected to work as intended. Our safety net becomes less robust, we make things less secure.

2.11 Load shedding can be used as the first line of defense when it comes to generation underfrequency protection

The MRO load shedding program is designed to be the first line of protection for the generators because it is designed to force frequency recovery even in the absence of governor action by having small blocks of load shed on delay to quickly bring us back towards 60 Hz when recovery is too slow.

2.12 Generation off-nominal frequency protection settings imply more risk than units may experience

Although there is a chance that frequency may be slow to recover as a worst case, most of the time it will recover much faster than the times we used for generation tripping coordination. The expected time spent below 60 Hz sort of takes on the form of a probability density function. This type of information gives a better idea of what units may be exposed to, and the real risk is less than what the generation protection settings may imply. Therefore, our approach was to coordinate generation off-nominal frequency protection to match the worst case frequency recovery times seen in our simulations after first doing everything possible to minimize underfrequency exposure to generators when designing the load shedding program. For the MRO region, the recommendations of the MRO UFLS report should take precedence over what is being proposed in PRC-024 and PRC-006.

2.13 UFLS programs which shed higher levels of load need less restrictive generation off-nominal frequency protection

In MRO, we recognize that the Canadian portion of MRO needs to shed more than 30% of connected load. The MRO UFLS report indicates that any program that needs to shed more than 30% of load will need to relax the MRO generator off nominal frequency time delay settings for generation and accept longer delays and lower minimum frequencies. This is an engineering reality. The Off-Nominal Frequency Capability Curve from PRC-024 does not give this kind of flexibility. Alternately, some improvement on minimum frequency can be realized by designing a program that oversheds but then the program will be prone to overspeed problems. This approach can get scary. Some improvement in coordinating with generation needs can be achieved by designing the UFLS program to start shedding at higher frequencies. This gives a corresponding improvement to the minimum frequency but this action often creates coordination problems with neighboring programs. On the other hand, sometimes you want one area to start shedding first to meet some specific objective. This is just another example of how every single facet of UFLS program design has to be carefully considered. In many ways, this is no different from any other type of planning or operating study work.

The bottom line is that this reliability standard writing process should not replace engineering judgment. Utilities need flexibility so they can make the necessary compromises after all things are considered. Making adjustments to generation protection frequency settings and associated time delays is most likely the best approach to ensure coordination with larger load shedding programs. We must give sufficient time for load shedding to act even if it means we need to accept some additional potential loss of life to generation for some hypothetical underfrequency event. I believe this is prudent and will not place undue

burden on generation.

2.14 The starting frequency of load shedding programs

In MRO we would have considered an UFLS program which starts to shed load at frequencies above 59.3 Hz (probably 59.5 Hz) if neighboring regions would have shown interest in doing the same. However that was not the case. All the programs in the region started at 59.3 Hz so we stuck with that. If we had increased the starting point to 59.5 Hz, we might have increased the risk of dropping load on power system swings where no load dropping is needed (if so, this would probably be isolated to a few buses), but we would have improve the minimum frequency and this helps larger load shedding programs meet coordination needs.

2.15 Turbine/Generator underfrequency capabilities

To talk about off-nominal frequency capabilities of turbine/ generators, I will once again have to generalize a bit. The continuous operating range for no accelerated loss of life is typically 60.5 Hz to 59.5 Hz. The frequency which requires an instant trip, for most generation (I will ignore combustion turbines for now), is below 57 Hz for steam, and as low as 56 Hz or lower for hydro. Steam turbines are more restrictive than hydro because of blade resonance issues and the result is that the time versus frequency limits are logarithmic with considerable operating time allowed just below 59.5 Hz and very little operating time is allowed at the lower frequencies. Limits are generally based on a theoretical “probable loss of life” after being subjected to some total time spent below 60 Hz over the life of the plant. This also fails to take into consideration that units get maintained and some issues are corrected before becoming problems. So we have to evaluate what fraction of this theoretical off-nominal frequency based accelerated loss of life needs to be used to respond to a rare and infrequent islanding event, but in the end this is a judgment call and is driven by what we have to accept to get the job done. Limits for combustion turbines seem to vary, with instant tripping suggested anywhere from about 57 Hz to 58.2 Hz. I know less about these than I do about other types of generation, but we learned what we could about these during the MRO UFLS study process. The group that did the last WECC UFLS review got quite involved in this area of investigation, and the MRO group benefited by consulting with the former chairman of that group. 20 years ago the combustion turbines were not showing up as a limiting factor, or we failed to notice the issues. I personally question the basis for the 58.2 Hz instant tripping point that is recommended for one make and model. It is hard for me to imagine that a very brief dip below 58.2 Hz is going to be a problem when considerable operating time above 58.2 Hz is allowed. This low “instant trip” frequency setting is out of line with historical industry practices and our industry has to encourage manufacturers to build equipment with better off-nominal frequency capability than this.

2.16 Don’t get too conservative with Generation off-nominal frequency protection settings

I feel that many times utilities try to get too conservative in how they want to set generation-off nominal frequency protection to the point where this may affect UFLS. If we set this too tight we might end up with a blackout. Black start plans are where the real off-nominal frequency loss of life can be chewed up. Generally such plans call for this protection to be disabled so that it does not interfere with restoring the system.

Another issue that I have heard several times as justification for using very conservative generator off-nominal frequency limits is that some folks are claiming their insurance sets underfrequency limits for their generation. Who is to say if the terms of the insurance coverage even makes any technical sense? This hardly sounds like a legitimate reliability issue. From my perspective, this seems at odds with system reliability. I also expect that independent power producers will not be as interested as a traditional vertically integrated utility would be in trying to prevent the grid from collapsing. I expect that at least some of them would just as soon shut down as quickly as possible instead of riding the disturbance out. We have to ensure they do not do this or it may have catastrophic consequences.

2.17 Short time delays being proposed for generation protection at frequencies close to 60 Hz is a huge risk to the grid, (i.e. at 59.3 Hz, 60.7 Hz)

We need to allow much more operating time at the frequencies closer to 60 Hz than what the NERC standards drafting teams are proposing in PRC-006 and PRC-024. The proposed time delay limit says we can only operate at or below 59.3 Hz or at or above 60.7 Hz for 30 seconds. This is completely unrealistic and a huge threat to system reliability because these standards are essentially giving generation permission to set protection relays accordingly. Remember that once generation starts to trip on underfrequency it can quickly cascade into a blackout. This entire subject of what is appropriate for generation off-nominal frequency protection is something for the experts in study groups to work out, and should not be addressed in either of these standards.

At frequencies close to 60 Hz the appropriate generation protection time delays need to be on the order of 30 minutes or longer instead of 30 seconds as proposed by PRC-006 and PRC-024.

The analysis we did in MRO indicates there is a chance that we will take longer than 30 seconds to get above 59.3 Hz even if our UFLS program works as planned. Remember we did this “bandwidth” type of analysis so we looked at more conditions than most have. We looked for those narrow windows of vulnerability where things “stick” or respond in a sluggish fashion. We can show that any UFLS program will have some combinations of overload and modeling assumptions where frequency recovery is

slow and sluggish. If you don't look for this problem, you are not going to find it, so we conclude the other regions would have as much trouble meeting this as the new MRO UFLS program. Perhaps an intuitive example will help. Basically over the range of coverage provided by load shedding, there will be certain combinations of factors which lead to frequency settling out just above where the next block picks up, and then we have to rely of governor action (or additional small blocks of load shed on delay) to pull the frequency back up. The rate of frequency recovery is also going to be a function of inertia, and if we have lots of units on which are partly loaded, the effective "system based" inertia will be high and rates of change of frequency will be lower. In comparison, if frequency would have dropped a little lower we would have quickly shed load and driven frequency up above 60 Hz, potentially reaching our maximum frequency. Another example to consider is what happens if the system overload is just a little larger than the size of the UFLS program? All load is shed and we are still below 60 Hz, but frequency might be close enough to 60 Hz for operators to respond if they are given sufficient time to respond.

2.18 Generation protection settings also have to anticipate what happens if UFLS fails

My biggest concern with use of short time delays at frequencies above 59 Hz is based on a completely different issue. Murphy's Law is alive and well when it comes to power systems. All of us have to consider what might go wrong during a system breakup. Breakups can be chaotic and different each time they happen, and consequently load shedding performance can vary. There is a chance the "perfect plan on paper" may fail to work as desired in the face of some unanticipated event. At some point operators may have to intervene, and they need assurance that generation will not be tripping as they manually try and drop load. The fact that frequency can stall us out below 59.5 Hz is reason enough to insist that we use generation protection time delays according to actual equipment capabilities. In general, generation off-nominal frequency protection time delays need to be longer than the expected frequency recovery times shown in simulations to give us some margin, and as we get closer to 60 Hz, we want to take advantage of the long delay times allowed by actual equipment capabilities. This is needed as part of the "hedging our bets" process. This helps compensate for the uncertainty we cannot factor into the program design like relay failure, operator error, random events, loads changing in real time (affecting block size as % of system load), effects of voltage transients that effectively increase load, and so forth.

A real life scenario many of us have seen before is where UFLS programs cycle between underfrequency to overfrequency and back into underfrequency. On the second drop into underfrequency, we no longer have all or any of our automatic load shedding left. With luck, the frequency will stall out close enough to 60 Hz to allow manual operator initiated actions. Planners try to prevent this in the design, but in real life this cannot always be prevented. For instance, load shedding itself can overstress lines and cause further breakup of an island into smaller islands, one with a surplus of generation and one with too much load. The island with too much generation is going to suddenly have severe overfrequency problems. Emergency overspeed controls which are in place to deal with full load rejection will kick in somewhere above 61.2 Hz (as previously described). At steam plants these load rejection controls will slam all valves shut. Power plants can't stay in this condition for very long before something gives. Let's say this leads to unpredictable random tripping of thermal generation, and frequency drops back below 60 Hz. As frequency drops the remaining steam turbine valves open back up, so the initial loss of generation my save the rest of the generation and frequency may actually settle out below 60 Hz, but with frequency still high enough that actual equipment capabilities would allow operators plenty of time to respond. We need to take advantage of this capability, and set generation tripping times accordingly.

Another example would be having an overload which is slightly higher than the size of the load shedding program. All load is shed, but frequency remains below 59.5 Hz. We then rely on manual operator actions to pull us back the rest of the way.

2.19 A very troubling trend

One of the most troubling things we uncovered in the MRO UFLS effort is that some manufacturers are now designing equipment which does not have the off-nominal frequency capability it once had. It seems this has occurred with CT's and is probably also happening with wind generation. I mention this trend as it is important that we don't build in weak links like this as the system expands or else we are going to seriously affect reliability. We need units which can briefly operate down to at least 57 Hz to improve chances of surviving islanding events. Future trends in general are all at odds with being able to create a good underfrequency safety net. If NERC prescribes limits which never allow us to operate below 58 Hz, or to limit operation at 59.3 Hz to only 30 seconds, equipment will start being built accordingly.

Combustion turbines cannot hold constant power as frequency drops unless they were only partly loaded to begin with. There are thermal issues involved, which is why fully loaded units only have a momentary governor response to underfrequency. The governor is quickly overridden by the thermal controls. The percentage of power which drops off due to a frequency decline is going to be about the same percentage as the percent change in frequency, or higher. A lot of new CT's have been added over the last 10 years or so, and we are likely to see more of these in the future.

High concentrations of wind generation are really going to cause problems unless more sophisticated designs are used. The problem is that older units are inherently unstable and will just trip off right away. Newer units can probably operate down to 57 Hz, but all inertial effects are masked from the system, so system inertia is going to drop and UFLS relay coordination is going to become very difficult because that low inertia means high rates of change of frequency and this can affect load shedding

programs in several ways. In the MRO UFLS program, we anticipated this problem and examined lower “system based” inertia than what we have today. We saw coordination problems, but this information was still used to help us define a robust UFLS program. It was obvious that coordination would be next to impossible if inertia got lower than what we looked at. Lower system based inertia means lower minimum frequencies and higher frequency overshoot. (This is a consequence of relay detection times and breaker operating times being too slow to stay on top of the fast drop in frequency, so we end up with relay coordination problems and shed too much, too late.) I am not aware of wind units having any type of governor although I was told by an individual in GE’s Power Systems group that designs will be changing over the next 10 years. For instance, GE is adding a governor to their wind generation. I am not sure how that works. Most likely it would work well on overfrequency, but I am not so sure about underfrequency. Likewise they might be able to use software that controls the power electronics associated with variable slip induction generator to unmask the inertial effects (or mimic such effects) to help the grid a bit. However, actual inertia of wind generation is still going to be low. I also heard that a new trend is going to be use of permanent magnet synchronous generators for wind generation. Synchronous generation is probably going to be an improvement over induction generation, but I have no idea if this will actually be a benefit to the system or not. Whatever the wind industry comes up with, it is unlikely to be as robust and useful as traditional steam and hydro generation, and it will just make the task of providing a safety net all the more complex, or perhaps nearly impossible, once huge amounts of wind generation are added to the grid.

3.0 Observations concerning historical reliability criteria, and a proposal to adopt a different type of “measure” to assess UFLS reliability

3.1 Reasonable Expectations

It appears that engineers recognize that we cannot apply performance measures to real life load shedding events since it would be an inconsistent application of how we apply operating type criteria in general to such low probability multiple contingencies. In addition, the parties who are trying to fix the problem do not need to be blamed for the problem itself should they be unable to “fix it”. That is sort of pointless. I believe that engineers also seem to recognize the only perfect program that exists is the one on paper. In real life it has to deal with things we probably have never anticipated and if disturbances are too severe, load shedding may not prevent collapse. Load shedding is just a tool and it has limits. That is just an engineering reality. It should also be obvious that a lot of coordination is involved.

3.2 Coordination is the key to ensuring reliability objectives are met

Good coordination is going to be what ensures reliability. However we sure seem to be doing things which discourages coordination at large. This new deregulated world has defined transmission as separate from generation when in reality all these parts together form a giant complex machine called the “system”. For compliance, we created the concept of “Legal Entities” who can be sanctioned, and entities such as NERC regionals that are apparently something else. We invented terms such as planning coordinator. This all gets confusing, especially to me, as I have had little experience with structural changes going on. What I see is that much of the carefully built up infrastructure that we had to promote reliability is being altered to the extent it is hard to recognize just where we are at today. As we keep creating distinctions which do not follow engineering realities, it will just make all of our coordination tasks much harder to achieve. It is hard to see how this helps reliability. For instance, I was told the NERC regions cannot be in charge of design and analysis of UFLS programs (in conjunction with members of course) because they are not a “Legal Entity”. However this is how reliability matters were always coordinated and this is still the logical way to achieve coordination between all of the parties who need to get involved. All of us in the industry have to work together and pull in the same direction to develop an appropriate safety net. The NERC regions have the organizational structure to pull everyone together to do this type of coordination through taskforces that represent the industry at large. It is necessary to get a broad base of different people involved in the UFLS study process. It ensures you have lots of eyes on the product, lots of different viewpoints to consider, and it also helps in selling and explaining the final program to everyone in the end.

3.3 We have to consider the system in total

When it comes to analysis, the power grid is all one giant complex machine all the way down to the customer load. You have to consider all the parts to figure out the dynamic response of the whole. We have to consider everything which affects the frequency decay dynamics. There is no distinction that can be made on the basis of voltage class of the components of the system. This is why I am a little uncomfortable with excluding some generation from having to coordinate with load shedding programs as done in PRC-024 and PRC-006 just because such generation is connected to a lower voltage. If such generation, in total, is significant to the study work and final UFLS program, then it needs to be included. Let the study group decide what is significant or insignificant.

3.4 The evolution of PRC-006

I understand that PRC-006 has now evolved into something closer to a “continent wide” planning type of standard to guide us in designing UFLS programs. I have tried to explain why the tradeoffs associated with load shedding programs are best evaluated by groups of technical experts which are closest to the problem and why this standards process should not be micromanaging the analytical process or be setting design type of performance criteria. Likewise, it is a poor idea to have a standard such as the proposed PRC-024 that tries to establish generator protection settings up front. I see these approaches as

actually being a threat to reliability by providing the wrong incentives (I also have technical reasons why I do not agree what is being proposed). NERC should allow the technical groups to work out these types of details. Such groups can give this subject the thought and focus that it deserves, and this careful deliberate thought process is what will ultimately ensure we are meeting reliability objectives.

3.5 A recap of my concerns

I believe that I have explained why I am uncomfortable with the idea of using specific frequency and voltage characteristics as a design "measure" in the UFLS standard. I will recap the issues. The various performance objectives of limiting underfrequency, limiting overfrequency, and of providing the largest safety net possible are mutually exclusive. The easiest way to satisfy all three (perhaps the only way) is to put in a smaller program and then the program will work well over this smaller range of overloads but will be inadequate if larger overloads occur. I believe we need to allow programs which are larger than the minimum, when appropriate, and those programs will have poorer performance according to these "measures" but I will argue that only the program which is "large enough to get the job done" will give us the reliability we are looking for. I also recognize there are limits to what UFLS can accomplish, which is why I do not want to mandate that UFLS programs have to shed more than the stated minimum, but I want to encourage folks to do this if it makes sense. Neither the frequency nor the voltage "measures" really tell us if we have the right safety net in place and both measures are subjective (i.e. what performance for what set of assumptions). Concerning voltage, I recognize that volt/Hz issues exist, but I do not feel this needs to be addressed in the standard. The real issue is how to minimize overvoltage problems as we shed load.

To some extent I believe this discussion also helps explain why it can make sense to have different UFLS programs for different portions of the system. That is because different areas have different needs, and possibly unique regional aspects to consider. The final UFLS program definition is just an outcome of working though the problem and iterating towards a best compromise for UFLS program design.

There is no one single "best" program. We have lots of options and each represents different tradeoffs. In reviewing technical literature, we find there are also lots of different opinions expressed by different authors, and I imagine this influenced how programs were created in the first place. I believe the existing load shedding programs in North America are probably getting the job done as long as coordination with generation protection has been achieved. Some programs may be a little more refined than others, but load shedding is inherently a crude and drastic action. A periodic review process will go a long way to ensuring we keep programs up to date. We do not want this review process to be too much of a burden, but we want some process in place so that we can do detailed analysis if needed. My experience has been that a full blown UFLS study process will take 2 to 3 years to complete, perhaps 1 to 1.5 years if folks are fully trained, spend all their time on this one subject, have the study scope worked out ahead of time, and have all the tools developed that are needed. That is what it took groups I have been involved with to collect the information, to build the models, to run meetings, to do the analytical work, and so forth. I would not want to have to do that over and over again on a 5 year schedule. A much more simplified review would be appropriate for the 5 year review. A full study mode type of ground up review is only needed once in a long while or in response to some major break up or in response to drastic changes to the topography of the grid.

I feel that UFLS "measures" used for compliance purposes should stay away from frequency and voltage. We need a different type of measure. UFLS is really sort of something different and unique, and I think that justifies treating it differently than other Standards to the extent that it makes sense to do so. All the other criteria try to keep us from ever getting to this point. UFLS is what we do when we are past the point where most criteria apply. It is a drastic, one shot, last ditch effort and we can't make it into something other than what it is. Some accelerated loss of life to equipment will be involved. Loss of equipment life and financial costs are also associated with a system that goes black. We need to consider all of these tradeoffs, especially when people get too conservative on generation protection to the point where if affects UFLS performance objectives. We need flexibility to accept the right tradeoffs. The UFLS standard can avoid the subject of voltage and frequency performance altogether since we know this will be addressed in the study process in an appropriate level of detail.

3.6 A suggestion to adopt a completely different type of "measure"

I have consistently stressed how UFLS analysis is an iterative process. I hope everyone can understand why I feel this standards drafting process also has to be iterative, and why we may need to change course as we move along the learning curve.

I believe the standards drafting teams need to back up and try a different approach which emphasizes "measures" which consider a completely different aspect of UFLS related effects on reliability. The question is, what are the right measures? The first thought that comes to mind is that load shedding enhances reliability by creating a safety net. Perhaps we should be only be checking to see if the safety net exists, to see if studies say the safety net is an appropriate safety net, and so forth. Would it be possible to use these aspects of the issue as our "measures"?

I think it makes perfect sense to "measure" if we are fulfilling the basic aspects of load shedding obligations. The "measure" would be "have you done activities x, y, z?". We would then skip this entire discussion of what type of performance, on paper, is

appropriate. Instead we would focus on the big picture, which is to make sure we have a reasonably effective safety net in place. The “measures” could become simple pass/fail checks to see if we have covered the basics of implementing an appropriate UFLS program. I suggest that we keep it really simple. It will be easy to check on things like: 1) has an appropriate program been designed which satisfies a checklist of items that have to be considered such as coordination with generation protection, 2) has the program been implemented, 3) has the program been periodically reviewed, 4) have any changes that came about from the review processes been implemented in a timely fashion, and so forth. I know I am in the position of having to sell this approach, as this is not what FERC and NERC set out to do. However, when you look at all the complexity involved, and what the bottom line is, this approach makes sense. I am sure it would be acceptable to the industry and that it would satisfy reliability objectives so long as we get the appropriate study groups in place. That really means getting the right people involved, who have the needed skills to work through things. I think a NERC region has the organizational structure to pull this type of coordination off. We are all familiar with that structure. Inventing some new type of group structure just adds another layer of confusion to deal with.

The standards should stick to the broad-brush type of stuff. More to the point, this standard should be written to ensure the following:

* That Automatic Underfrequency Load Shedding (UFLS) programs are properly developed, documented, and coordinated. This includes coordinating generation off-nominal frequency protection settings with the expected frequency recovery characteristic of the load shedding program.

* That groups/regions have studied UFLS and have designed an UFLS program that fits the unique characteristics of the region (including any subregions) and that UFLS programs address any specific issues that are relevant to UFLS.

* That groups/regions have documentation that specifies the details of the desired UFLS program so it can be implemented.

* That groups/regions do periodic reviews including reports on actual UFLS performance following major disturbances.

* That individual utilities have implemented load shedding in a fashion which is a reasonable fit to the stated regional load shedding program and that documentation is available (the term “reasonable fit” is used in consideration that no single utility can ever get a perfect match to a something like 5 blocks of 6%).

* That each group/region sheds at least a minimum amount of load.
That some form of coordination or dialog exists between groups/regions which study load shedding in adjacent areas.

* To ensure that modeling data is collected and compiled for stability cases

We recognize that PRC-006 addresses some of these points adequately, but as previously discussed, we have serious concerns with how some of this is being handled.

Let the groups/regions define:

* how much load to shed in total (it is OK to set a minimum level in the NERC standard, so long as we are clear that this implies a higher level might be more appropriate)

* size of load shedding blocks

* frequency setpoints

* targets for min/max frequency deviations and allowable times above and below 60 hz (these are design targets only, and may have to be reconsidered and revised after looking at study results…this is an iterative process that has to be carefully thought out as study work proceeds)

* generation off-nominal frequency tripping minimum time versus frequency protection settings to ensure coordination with load shedding

* analytical methods

* any other unique requirements or aspects of regional programs

3.7 The existing NERC UFLS related guidelines and criteria are excellent

As far as UFLS design goes, the broad guidelines in the existing NERC UFLS related standards are excellent, and following that lead will allow us to reach the correct final conclusions. Somehow we have to retain all of these guidelines.

4.0 Can the measures in PRC-006 be tweaked, and is that even a fix?

I believe the direction taken in PRC-006 and PRC-024 is seriously flawed making a discussion of how to tweak and fix things sort of meaningless. That is why I am proposing we adopt “measures” that are based upon the “activities” required to get a safety net in place instead of a measure of “technical details”. However, if we are unable to change directions, then the proposed performance “measures” have to be softened to allow exceptions as based on needs identified in analytical work and to base criteria on actual equipment capabilities. We need a lot of freedom so that groups can make the needed compromises and adopt the right performance criteria.

I really don’t think that PRC-006 should be a planning type of standard that tries to micromanage the design process. My opinion is this approach will not ensure reliability objectives are met. We only need to point out the various issues which planning engineers have to consider (this is clearly spelled out in old NERC UFLS standards) and they can take it from there and work through the study process. Planning engineers will understand what needs to be done better than anyone else. Just turn them loose and they will get the job done, and then we will have the UFLS program specifications complete with criteria on how to coordinate with generation protection.

The existing NERC UFLS related standards are still highly relevant materials which should be used as guidelines on how to develop load shedding programs.

While it is reasonable to start with tentative performance targets as far as design work goes, I consider this as something best left to a study group of the technical experts. Study work has to be performed to find out what is possible before you reach a final decision about what is the best compromise for an UFLS program. In the end, the final program will have to consider if a given area has any unique characteristics that have to be considered, and study work will involve tradeoffs and compromises concerning minimum frequency, maximum frequency, time spent below 60 Hz, and so forth.

4.1 List of specifics related to PRC-006.

R1- a group of planning coordinators is not going to be the equivalent of the type of broad based participation we have historically achieved through the NERC Regionals via the existing committee structure. The group concept is a step in the right direction, but the concerns that we can only apply mandatory standards to “legal entities” appears to be leading to artificial constraints that are making it more difficult to achieve the needed coordination and this just makes it more difficult to create the safety net that we want.

R2-stresses consistent application across the region, and I would argue that only the final analysis of the system will tell you if this makes sense. There may be subregions which have different needs. In MRO, the Canadian systems have different needs than the US portion of MRO.

R3- this says we need criteria on how to select islands. It strikes me as odd that we need “criteria” on how to reach a conclusion. Shouldn’t this just say that analysis shall consider possible system break up patterns that may form islands? For the US portion of MRO, we did not try to say what the most likely island would be. Instead we identified where the break points were, and used this, along with the MRO geographic boundary, to break the system into pieces. We felt these pieces alone, or aggregated together, represented our possible islands. We evaluated the needs of each of the pieces, and evaluated how to model each piece. We concluded that one set of simulations covering a range of inertia, damping assumptions, and overloads would inherently cover all of these different islanding patterns. So we performed our analysis in a fashion that allowed us to avoid having to make a very specific determination of what the island would be, and instead found a way to make something work in a more global sense.

R4-I agree that coordination with neighboring regions is required, but I do not know how to resolve differences of opinion between regions. Perhaps this is nothing to worry about since it is likely to take care of itself. Are we trying to reach a consensus between regions, or just trying to share information and to create a forum for discussion? Obviously where breakups cause islands that straddle different NERC regions, we need to jointly evaluate that island. Even if this coordination is only to share information, it still allows everyone to learn from each other and is going to be quite valuable.

R5-is about identifying islands. I think it is the exact wording of this section that bothers me although I agree with the intent. I prefer to focus on break points that may lead to islands. The difference is subtle, but for the US portion of MRO we did not identify “an island”, in the traditional sense, that was the basis for our design. We identified how the grid may break up. We used these break points to break the system down into pockets of load and generation, and then we examined each pocket. These

pieces, alone or aggregated together, are our possible islands. We did not try to say which was most likely to form. Some of this represents high unlikely conditions. Some of our parts were not even expected to be islands, and were just the left over parts of the foot print after the obvious break points were identified. The southern and eastern edge of MRO is tightly interconnected and less likely to island, but we still were able to reach a conclusion as to what load shedding level was appropriate for even these areas. We examined load shedding requirements and modeling characteristics of each part. In the end we decided that a 30% load shedding requirement was adequate for each "piece" except for the systems in Saskatchewan and Manitoba. The MRO approach was to allow those regions to have their own programs, so they could satisfy their needs, and we just concentrated on the US portion of MRO. In the US portion of MRO, we found an UFLS program that should work for any of these island patterns as each of the geographic regions we looked at had similar characteristics and load shedding needs. We could model a range of conditions using the equivalent inertia modeling approach and we would inherently capture everything at once. Although our analysis was rigorous, we avoided having to decide on what our island has to be for design purposes, and instead came up with something that is likely to work for about any islanding pattern. With this said I can propose a wording change, I would rather say something like:"…shall identify islanding patterns that can be used as a basis for designing an UFLS program. This shall consider:"

R6-addresses the "technical parameters" that I have so much trouble with. I have problems with all of this, as previously discussed at length. I do not like R6.1, R6.2, R6.3 at all, but as part of the study process we would normally come up with parameters of this type after we work through all of the tradeoffs. However I expect we would decide on different technical parameters in the end than is being proposed in PRC-006 and PRC-024. Requirement R6.4, the volts/Hz requirement, does not seem appropriate, and may not have to be addressed at all in an UFLS program. The need to address volts per Hz would depend on how low of a minimum frequency we are expecting. This does not appear to be an issue for programs where the minimum frequency is above 57.2 Hz or so. This might be relevant to isolated hydro systems with large load shedding requirements because hydro systems can accept much lower minimum frequencies than thermal generation (below 57 Hz) and load shedding programs may want to exploit that characteristic. However this would be something that study groups would apply as needed, and does not need to be in a standard.

R7-is about the need to do periodic assessments. I agree we need a periodic assessment of some sort. Full blown studies on the other hand are seldom required unless some inherent flaw in an existing program is identified and we need to start with a fresh look at everything. I do not agree with meeting the performance characteristics in R6. We should meet performance characteristics which are defined as a result of the load shedding study process, and not just something that is tossed out up front.

I think there are other ways to assess the risk of having units trip off early than just running simulations. This almost implies we have to use full stability cases as our only analytical method. Let engineers figure out how to study the problems using whatever tools, methods, and calculations they feel are appropriate.

If we require some assessment of load shedding "need", then generation which drops off early can be evaluated in terms of how it affects the "needs" assessment, or we can demonstrate how loss of such generation affects programs in a general sense. Personally I feel we should not allow any generation to trip any sooner than prescribed by the final UFLS programs requirement for generation protection settings and delays. On second thought, there will be a few exceptions: units which are unstable like the older wind units, non-utility generation tripped along with load on a feeder as part of UFLS, and perhaps other exceptions where inadvertent tripping cannot be avoided. However, as a general principle, we should not allow any generation to trip prematurely via dedicated under frequency relays unless some offsetting action like tripping additional load can be done. We should not allow generation tripping on overfrequency using dedicated relays (other than tripping actions related to load rejection protection that we do not want to be messing with), unless such overfrequency tripping of generation is a planned activity that is a feature of the UFLS program used to rebalance load and generation.

R-8 shouldn't this database/modeling type of information be compiled as part of the regional model building process? NERC regions do this type of thing today, why is this group of Planning Coordinators getting involved in this. We use the NERC regions to do our coordinating activities, so why depart from what works? I need to understand the reasoning behind this before I can comment further.

R-9 appears to say that everyone shall trip load in accordance with the UFLS program. I agree with the intent.

5.0 Appendix

I wrote a lengthy document and sent it to NERC when the first draft of this standard was out for comment. As I just emailed that document in directly and did not submit that document through the on-line data forms where comments are provided, my critique did not show up along with all of the other comments. So, I am submitting some of this again as an appendix. Below are the portions of my original document which address the physics of the problem. I imagine some of this has already been discussed above. However, this is still a good review.

5.1 UFLS in Context

Before we can really address the Under Frequency Load Shedding Regional Reliability Standard Characteristics document in specific detail, we need to provide a context.

Reasonable expectations:

* Under frequency load shedding (UFLS) is a one shot, last ditch attempt to save the grid from total collapse for some event that typically far exceeds anything that planning or operating criteria addresses.

* Load shedding is inherently a crude and drastic action.

* Load shedding has its limits, it can't protect against everything.

* There is no perfect UFLS plan, just lots of different options with lots of different tradeoffs.

* In any discussion of UFLS, we need to keep in mind that load shedding might not work as desired in real life, and we can only make it "perfect" on paper, for some tightly defined scenario subject to a lot of assumptions.

* Just about any UFLS program will work great for some overload level, but at a different overload levels it might shed too much and cause a frequency overshoot or shed too little and then frequency might stall out. We can try to minimize such problems, but not totally eliminate them.

* Doing "something" to try to quickly correct a major load/generation imbalance is better than doing nothing, and history has shown that load shedding generally works well, but it is not always trouble free. Don't penalize honest efforts to provide a safety net.

The best we can do is to eliminate any obvious flaws in the UFLS program design and try to anticipate complications.

5.2 Trade-offs, Compromises, and Uncertainty

When it comes to designing a program, engineers find there is considerable uncertainty associated with most every aspect of the problem. Consider:

* We do not know what may lead to break up, or necessarily what islands may form or what the final imbalance may be.

* There is no perfect way to determine how islands will form, especially if the region is tightly interconnected. Study tools such as stability cases may help identify possible islands, but experience and engineering judgment is perhaps more important.

* Factors that affect load shedding performance are not necessarily under the control of the utilities who put in load shedding.

* At best, we can bracket a range of unknowns and make educated guesses, and then try to find a program that works as intended, the most often, over the widest range of conditions.

* This type of work involves lots of trade offs and compromises.

Compromise also applies to simulation methods. No simulation approach is going to be perfectly suited for this type of analysis and each of the standard ways of assessing UFLS has strengths and weaknesses.

* Full stability cases are very detailed and good for a very specific spot check, but poor for generalizing. They do not necessarily provide a better way of assessing system performance than a more empirical approach.

* Relay application guides typically suggest using the equivalent inertia approach to dynamic modeling where everything is equivalized down into the simplest form that captures the frequency decay dynamics. This simple approach allows rapid prototyping, but it ignores the voltage transients and governor action.

To better understand the complications of UFLS design, we need to give a brief statement of the problem:

* When we have a mismatch of load and generation, the frequency will decay or increase until we reach a new equilibrium between generation torques and load torques.

* If generator power stays constant, then generation torque will increase as frequency drops (power = torque x speed).

* Load torques decrease as frequency drops according to the load damping constant.

* At some new frequency, we once again reach equilibrium where load and generation torques are equal and this becomes the new synchronous frequency.

* Without load shedding we could see frequency decay low enough that generation protection will have to instantly trip generation to prevent excessive loss of life. At that point, the system collapses.

Load shedding objective and tradeoffs:

* We use UFLS to quickly drive frequency back towards 60 Hz so that we do not risk losing additional generation on underfrequency.

* Loadshedding must not cause overfrequency problems that lead to uncontrolled tripping of generation that will precipitate another underfrequency event.

* To improve minimum frequency, we can start shedding sooner (higher frequency setpoints), decrease frequency spacing between relay settings, and shed load in fewer blocks of larger size…all of this increases frequency overshoot problems.

* We can also improve minimum frequency by deciding to cover a smaller imbalance to begin with.

* To decrease frequency overshoot, we can shed load in smaller blocks, increase frequency spacing between relay settings, and use more load shedding blocks in total…all of this decreases the minimum transient frequency for the largest overloads we cover.

* Overfrequency based tripping of generation or restoration of load can also minimize frequency overshoot, at the risk of causing the frequency to cycle back into another underfrequency event.

* Underfrequency recovery times can be improved by shedding some additional blocks of load on delay, at the expense of increasing the risk of frequency overshoot.

The rates of change of frequency and load damping characteristics affect relay coordination:

* Large overloads give high rates of change of frequency

* Unit inertia represents energy stored in the rotating mass. Inertia (for a given overload level) affects the rate of decay of frequency: high inertia = slower frequency rate of change, low inertia = fast frequency rate of change.

* Load damping affects the final frequency where equilibrium is reached. Low damping means larger frequency deviations for a given imbalance.

* Generally it is difficult to design a program for low inertia, low damping, high overload conditions. This condition gives the lowest transient frequency, and the fast frequency decline affects relay coordination that can cause overshedding.

* Relay coordination is much easier if inertia is high, but recovery back towards 60 Hz will be slower when inertia is high.

Let’s consider some of the hard to quantify factors that affect performance:

* load damping (utilities have no control over the dynamic characteristic of loads, and we are not sure how much damping we have or how it varies in time or by season)

* the type of generation on the system

* the system inertia on system base (energy stored in rotating mass relative to remaining generation in island)

* if asynchronous islands are still being fed by DC lines (this is power with no inertia associated with it, which drives system based inertia down), or if frequency deviations cause DC lines to trip

* the magnitude of the imbalance between load and generation

* the net governor effect (not much if units are base loaded, running in boiler follow mode, or overridden by power-load controllers)

* overvoltages (and how can we moderate voltage deviations)…as load is shed the voltage will swing around, and overvoltages can increase load, offsetting the benefits of load shedding which in turn affects the rate of frequency recovery

* random factors, such as unit trips, industrial load trips, additional line outages (including planned separation schemes), and so forth

* Wind generation…the older vintage of wind generation will drop off-line as frequency declines…how much will be on-line?

* Combustion turbines…they are thermally restricted. Assuming a combustion turbine is operating close to its temperature limit to begin with (i.e. the typical condition when loaded high), the net result is that turbine power drops as frequency starts to decline, aggravating the imbalance.

* The actual sequence of events that leads to islanding can have considerable influence on overall performance, yet typically the best we can do in simulations is to form and island all at once by opening all the tie lines at the same moment. This is because we do not get major system breakups from “credible events” that we can easily model. Usually load shedding occurs following a complicated sequence of things going wrong that no one could have ever predicted ahead of time.

* Load shedding itself may overload transmission lines, and lead to further system breakup and islanding.

* Overshedding can lead to unintended random loss of additional generation in response to overspeed (due to various internal problems at the facility), and cause another cycle into underfrequency from which we might not recover.

Now consider future trends:

* Industry trends show that load damping is decreasing, and load damping is not precisely known to begin with. Damping also varies in real time.

* The trend has been that inertias of new units are lower than in the past.

* Some of the newer wind generation provides no inertial effects as rotating mass is decoupled from the electrical grid by the controls that allow variable slip operation of the induction generator or because they are coupled to the AC system through an inverter.

* Wind generation is intermittent, difficult to factor into UFLS programs, and with all of the different makes and models out there, it is difficult to generalize how these units will actually respond and how many will ride through a frequency swing.

Different areas have different load shedding needs, and areas that need to shed a lot of load have to make more compromises as far as transient frequency and voltage performance go:

* UFLS programs that shed more load will also experience lower minimum frequencies, higher maximum frequencies, and be more prone to relay coordination problems (which increases the chance of overshedding). On the positive side, these programs provide the largest safety net.

* Programs which shed the minimum amount of load can use smaller load blocks or fewer load shedding stages which improves frequency response and improves relay coordination over the smaller range of overloads covered. Obviously if overloads exceed the capacity of the program, the system will collapse.

In summary, everyone needs to apply common sense and good judgment when dealing with UFLS issues, and compromises have to be carefully considered at every step of the decision process involved with design and implementation.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard Project 2007-01: Underfrequency Load Shedding (PRC-006-1)– **Supplemental SAR Request**
Request Date 09/29/09
SC Approval Date October 7, 2009

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Stephanie Monzon	☐	New Standard
Primary Contact	610.608.8084	☒	Revision to existing Standard
Telephone Fax		☐	Withdrawal of existing Standard
E-mail	Stephanie.monzon@nerc.net	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

The purpose of the SAR is to include EOP-003-1 Load Shedding Plans in the scope of the existing project 2007-01: Underfrequency Load Shedding. EOP-003-1 contains requirements that conflict or are redundant with the requirements being proposed in PRC-006-1 (UFLS). The team thinks that the requirements specific to Underfrequency Load Shedding in EOP-003-1 need to be revised to remove inconsistencies and redundancies.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The UFLS standard drafting team received comments in the second posting that highlighted the conflict between the draft PRC-006-1 and the existing EOP-003-1 standard. Not addressing the conflicts in EOP-003-1 may cause compliance issues and general confusion regarding UFLS responsibilities.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The scope of the standard action includes revising EOP-003-1 requirements related to Underfrequency Load Shedding.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Project 2007-01: Underfrequency Load Shedding
Review of Issues from Database

Source	Language
Other	Modify standard to conform to the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure
PRC-006-0 — Development and Documentation of Regional ULS Program Requirements	
FERC Order 693	Transfer responsibility from the regional reliability organization to the regional entity.
	SDT Response: Order 672 says that requirements are applied to users, owners and operators. As such the drafting team applied the requirements to entities in the Functional Model not the Regional Entities.
Fill in the Blank Team	• Modify R1 to require each Region to develop a regional standard, and • Development of regional standards needs to be coordinated with Regional entities. Regional entities should begin process for developing regional standards once the drafting team for the North American standard has determined what elements of UFLS should be included in the continent-wide standard and what elements should be included in the regional standards. • Determine what elements (if any) of UFLS should be included in the North American standard and what elements should be included in the regional standards. • Related PRC-007, PRC-008, and 009. • PRC-006 will be a continent-wide standard supported by Regional Reliability Standards.
	SDT Response: • The drafting team is not requiring the Regions to develop regional standards. Instead, the drafting team is proposing common performance characteristics that all UFLS programs must meet. • This issue is not within the scope of the continent wide drafting team; however, many regions have begun development of UFLS standards. • The UFLS drafting team is proposing performance characteristics in version 3 of the draft standard.
Version 0 Team	• Not a standalone standard • Who do you submit compliance material to? • Need to define evidence
	SDT Response: The drafting team has clarified responsibilities for entities including database related responsibilities.
PRC-007-0 — Assuring Consistency with Regional UFLS Programs	
FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000	In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding

	accountability for loads served by retail marketers/suppliers. For additional information see: • FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) • NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), • FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and • NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.
	SDT Response: The drafting team is not assigning responsibilities to LSEs in the proposed standard. The team thinks that the appropriate entities, following the guidance in the Functional Model, have been identified in the proposed standard.
Fill in the Blank Team	• The regional procedures need to be converted to a standard to implement this. • Change "program" to "standard" in R1. • Coordinated with PRC-006.
	SDT Response: • The drafting team is proposing performance characteristics that UFLS programs must meet. • It is not within the scope of the drafting team to convert regional procedures into standards.
Version 0 Team	• Need to refine levels of non-compliance • Need to include RA
	SDT Response: • The drafting team has applied compliance elements based on the guidelines in FERC Orders and NERC's standard drafting team guidelines.
PRC-009-0 — UFLS Performance Following an Underfrequency Event	
Fill in the Blank Team	• See notes for PRC-007. • Change "program" to "standard'.
	SDT Response: • The drafting team is proposing requirements to be applied to UFLS programs (not standards).
FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000	In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: • FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) • NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), • FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and • NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.

	SDT Response: The drafting team is not assigning responsibilities to LSEs in the proposed standard. The team thinks that the appropriate entities, following the guidance in the Functional Model, have been identified in the proposed standard.
Version 0 Team	• Exemptions for those with shunt reactors who don't shed load • 90 days vs. 30 days • Define evidence
	SDT Response: • The drafting team is not proposing any exemptions for shunt reactors. The requirement indicate that responsible entities are to provide load tripping and switching of elements according to the UFLS programs and the UFLS programs may or may not have such exemptions.

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Unofficial Comment Form for 3rd Draft of Underfrequency Load Shedding Program Requirements — Project 2007-01

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit comments on the proposed 3re draft of the Underfrequency Load Shedding Program Requirements developed by the standard drafting team for Project 2007-01 – Underfrequency Load Shedding. Comments must be submitted by **July 16, 2010**. If you have any questions please contact Stephanie Monzon at stephanie.monzon@nerc.net or by telephone at 610-608-8084.

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Background Information

The major objectives of Project 2007-01 Underfrequency Load Shedding (UFLS) are to:

1) Ensure UFLS programs are developed to provide an appropriate level of reliability (not least common denominator).
2) Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.
3) Address the issues raised by FERC Order 693 and other applicable orders.
4) Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5) Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

The standard drafting team (SDT) for Project 2007-01 Underfrequency Load Shedding based its work on the existing NERC Reliability Standards:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs,
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements, and
- PRC-009-0 — UFLS Performance Following an Underfrequency Event.

Project 2007-01 Underfrequency Load Shedding is one of four projects[1] identified in the Reliability Standards Development Plan: 2008-2010 as requiring a set of Regional Standards to support a continent-wide standard.

In accordance with the associated SAR, a standard drafting team was appointed to draft the continent-wide UFLS standard with consideration of developing supporting regional standards. For the first posting the team recommended that, instead of developing a continent-wide standard, NERC issue a set of UFLS performance characteristics required in regional reliability standards for implementing automatic UFLS programs to arrest declining Bulk Electric System frequency. The team posted the set of UFLS performance characteristics for comment and received valuable feedback. However, many comments expressed concern that a directive containing these performance characteristics was a new form of "requirement" and would not necessarily follow the NERC standards development process including future revisions to the performance characteristics with industry input.

[1] The other three projects were, Project 2007-05 Balancing Authority Controls; Project 2007-11 Disturbance Monitoring; and Project 2008-04 Protection Systems

Considering industry feedback and the intent of the Rules of Procedure regarding directing regional reliability standards, the team evaluated many options that would preserve the existing regional entity expertise relative to defining credible islands within or between its region and neighboring regions and expertise in assessing islands within their regions based on electrically interconnected areas. The team also considered the role of the Planning Coordinators in their analysis as the functional entity most suitable to determine the UFLS program design given that the Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements.

After much deliberation, the team decided to convert the "Characteristics of UFLS Regional Reliability Standards" into a continent wide standard that will follow the standards development process and presented these requirements to the industry in the second posting in early 2009.

In the development of the third draft of the standard the drafting team considered the industry comments and made several clarifying and technical changes to the requirements. The following is a summary of the changes made to the standard.

Applicability

The applicability section of the second draft of the standard included "Distribution Providers" and "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load." This second draft language reflected the SDT's intent to establish the applicable entities in the UFLS standard to be those entities that supply UFLS capability. However, as a result of comments submitted in the second posting and further discussions within the SDT, the SDT now believes that the identification of the applicable entities was not an entirely accurate reflection of the participating registered entities. Therefore, the applicability section was modified. The SDT is now proposing the that "UFLS entities" within the standard shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include Transmission Owners and/or Distribution Providers. The concept to define a group of entities within the body of the standard in the Applicability section currently exists in the CIP-002-1. In addition, the SDT included Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators in the applicability. Transmission Owners would be subject to the standard if they have been identified by the group of Planning Coordinators as having the obligation to switch certain Elements as part of the UFLS program.

In the second posting, many of the requirements were assigned to groups of Planning Coordinators. These groups were to consist of all the Planning Coordinators within each of the Regional Entity footprints. The SDT has now revised these assignments to replace the groups with individual Planning Coordinators due to difficulties involved in assigning responsibilities to groups that do not currently exist.

Review of Technical Changes to Standard

The SDT has revised the under and overfrequency performance characteristics to refer to under and overfrequency curves (as Attachments 1 and 2) rather than discrete points as in former drafts. The SDT believes that curves provide more uniform coordination with generator under and overfrequency tripping requirements being proposed in PRC-024-1. In addition, the team extended the underfrequency performance characteristic curve to 60 seconds from the previous 30 second duration. The team agreed to extend the underfrequency performance characteristic to permit the MRO Region to avoid having to

specify a variance to cover instances where there may be slower recovery of frequency. The SDT believes that recovery of frequency within 60 seconds, though somewhat less stringent than requiring recovery within 30 seconds, remains acceptable for reliability and for coordination with generator underfrequency tripping. The SDT has similarly substituted the discrete points used in former drafts, for identifying which generator trip settings need to be included in the assessments of UFLS program design, with curves. These curves are shown on the same graphs as the performance characteristic curves (in Attachments 1 and 2) and are the same curves as are being proposed in PRC-024-1 for generator under and overfrequency tripping, thus ensuring explicit coordination between UFLS and generator tripping.

The SDT has modified the approach for ensuring coordination between regions and for selecting islands that overlap adjacent regions within an interconnection. The SDT has deleted the requirement that involved the development of procedures for coordination between groups of Planning Coordinators in neighboring regions in selecting interregional islands (version 2 of draft standard Requirement R4). In version 3 of the draft standard, any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating this selection with neighboring regions. The SDT has added a requirement for the Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by any one Planning Coordinator that encompasses more than one Planning Coordinator footprint. This revised approach to interregional coordination is contained in Requirements R5 and R13.

Some commenters noted that switching of certain transmission facilities is sometimes necessary to be carried out as part of a UFLS program design. The SDT agreed and has added Requirement R10 which requires Transmission Owners to provide automatic switching of Elements in accordance with the UFLS program design should a Planning Coordinator determine that such switching is a necessary part of the UFLS program design.

The SDT has added requirements to include an assessment of the performance of UFLS programs “within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load.”(Requirement R11). Requirement R12 requires the Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, to conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. Lastly, Requirement R13 requires the Planning Coordinator, in whose footprint an islanding event affecting multiple Planning Coordinator footprints and resulting in 500 MW or greater of UFLS actuated loss of load occurs, to reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment completion. In the former drafts, event analysis was left to be covered by the NERC Rules of Procedure. However, it is now believed that including a requirement in this standard for UFLS event analysis is a more appropriate mapping of PRC-009-0 Requirement R1 which will be replaced by this standard, PRC-006-1.

Hydro-Quebec Variance

Earlier in 2009, NPCC identified the need for a variance to the standard for the Québec Interconnection within NPCC. Due to the physical characteristics of the Québec system the UFLS program in Québec arrests frequency at a lower threshold and permits higher frequency overshoot than allowed in the proposed standard. The installed generation in the Québec Interconnection is 98 percent hydraulic generation, allowing wider tolerances on frequency performance without jeopardizing reliability. The variance also establishes a different capacity threshold for the generating units for which underfrequency and overfrequency trip settings must be modeled to address concerns that by 2020, 10 percent

of the installed capacity in Québec may be located at plants less than 75 MVA. The Standards Committee appointed a member from the Québec Interconnection to the drafting team to develop the variance for Québec. Working closely with this representative, the team developed the variance to Requirement R3 parts 3.1 and 3.2 and Requirement R4 parts 4.1 and 4.2. The variance to these requirements reference separate under and overfrequency curves included as attachments 1A and 2A to the standard.

EOP-003-1 Revisions

In reviewing the responses to comments on the second posting, several commenters noted that certain requirements in the exiting EOP-003-1 standard conflict or are redundant with the requirements being proposed by this SDT. The team agreed with these commenters and felt that if left unaddressed, the redundancies and conflicts could result in compliance issues in the future. As a result, the team submitted a request to supplement the existing SAR for Project 2007-01 to include a revision to EOP-003-1 in order to exclude those requirements related to automatic underfrequency load shedding since PRC-006-1 will contain these. The Standards Committee approved this action and the team moved forward with revising the existing EOP-003-1 requirements. The team is presenting these modifications to the EOP-003-1 requirements in this third posting of the standard and would like industry feedback on the revisions noting that the changes were conducted with the limited purpose of removing automatic underfrequency load shedding from the scope of EOP-003. Two other drafting teams are already in place to review the other aspects of EOP-003 as part of Project 2009-02 – Real-time Tools and Project 2009-03 – Emergency Operations.

The following questions will assist the SDT in finalizing the development of the Underfrequency Load Shedding continent wide standard. For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position. To improve the Underfrequency Load Shedding continent wide standard, the SDT would appreciate responses to as many of these questions as you can answer.

1. The SDT drafted Violation Risk Factors, for the requirements. Do you agree with the proposed Violation Risk Factors?

   ☐ Yes

   ☐ No

   Comments:

2. The SDT drafted Measures for the requirements. Do you agree with the proposed Measures?

   ☐ Yes

   ☐ No

   Comments:

3. The SDT drafted Violation Severity Levels for the requirements. Do you agree with the proposed Violation Severity Levels?

   ☐ Yes

   ☐ No

Comments:

4. In the second posting, many of the requirements were assigned to groups of Planning Coordinators. These groups were to consist of all the Planning Coordinators within each of the Regional Entity footprints. The SDT has now revised these assignments to replace the groups with individual Planning Coordinators due to difficulties involved in assigning responsibilities to groups that do not currently exist. Do you agree with this revision?

   ☐ Yes

   ☐ No

   Comments:

5. Several commenters indicated in the second posting potential conflicts and redundancies between PRC-006-1 and EOP-003-1 requirements. The SDT agrees that EOP-003-1 contains requirements that are redundant and/or conflict with the proposed requirements in PRC-006-1. The SDT sought approval to post a supplemental SAR to include EOP-003-1 Underfrequency Load Shedding related requirements in the scope of the UFLS SDT. The SC agreed to post the SAR with a proposal to revise the original scope of the UFLS SAR and the SDT revised the EOP-003-1 requirements to remove the conflicts.

6. Do you agree with the expanded scope in the Supplemental SAR?

   ☐ Yes

   ☐ No

   Comments:

7. Do you agree with the revisions to EOP-003-1?

   ☐ Yes

   ☐ No

   Comments:

8. Based on industry supplied comments, the SDT modified the applicability of the standard from “Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider’s load” and “Distribution Providers” in the second posting to “UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include Transmission Owners and/or Distribution Providers” in an effort to more appropriately identify those entities responsible for providing UFLS coverage. Has the SDT correctly identified the proper entities for UFLS coverage?

   ☐ Yes

   ☐ No

   Comments:

9. The SDT has modified the performance characteristics in Requirements R6.1 through R6.3 (now parts 3.1, 3.2 and 3.3 of Requirement R3) and the modeling requirements for generator underfrequency and overfrequency protection in Requirement R7.1 and

R7.2 (now parts 4.1 through 4.6 of Requirement R4). The modifications replace the discrete points in these requirements with frequency-time curves that achieve the same reliability objective. The SDT agrees with several commenters in the second posting that this approach is easier to understand and better demonstrates the coordination the SDT has achieved with the requirements proposed by the Generator Verification SDT in proposed standard PRC-024. Do you agree with these changes?

☐ Yes

☐ No

Comments:

10. Besides replacing the discrete point thresholds in R7.1 and R7.2 (now parts 4.1 through 4.6 of Requirement R4) with curves, the SDT has clarified which generators with under- and underfrequency trip settings above and below these curves, respectively, must be included in the UFLS assessments in parts 4.1 through 4.6 of Requirement R4. The generators with non-conforming trip settings that must be included in the UFLS assessments are now limited to individual generating units greater than 20 MVA or generating plants/facilities greater than 75 MVA directly connected to the BES or any facility consisting of one or more units that are connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. This clarification also makes parts 4.1 through 4.6 consistent with the generator size and connection thresholds in part 3.3.1 of Requirement R3. Do you agree with this clarification?

    ☐ Yes

    ☐ No

    Comments:

11. The SDT has replaced Requirement R4 appearing in the previous (second) draft of the standard. Requirement R4 required each group of Planning Coordinators to develop a procedure for coordinating with groups of Planning Coordinators in neighboring regions within an interconnection to identify and reach agreement on islands between its region and neighboring regions within the interconnection. Requirement R4 was removed because procedures for coordination do not directly support reliability. In version 3 of the draft standard, any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating this selection with neighboring regions (Requirement R1). The SDT has added a requirement for the Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by any one Planning Coordinator that encompasses more than one Planning Coordinator footprint (Requirement R5). Do you agree with this revision?

    ☐ Yes

    ☐ No

    Comments:

12. The SDT added a Requirement R10 that requires each Transmission Owner to provide automatic switching of Elements in accordance with the UFLS program design. The SDT added this requirement in response to comments submitted in the second posting of the standard that indicated that automatic switching of Elements may be important as part of the UFLS program design. Do you agree with this requirement?

    ☐ Yes

☐ No

Comments:

13. The SDT added new Requirements, R11 through R13. Requirement R11 requires each Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, to conduct and document an assessment of the performance of UFLS equipment and the UFLS program effectiveness within one year of event actuation. Requirement R12 requires Planning Coordinators, in whose islanding event assessments (per R11) UFLS program deficiencies are identified, to conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. Lastly, Requirement R13 requires Planning Coordinators, in whose footprint a BES islanding event affecting multiple Planning Coordinator footprints and resulting in system frequency excursions below the initializing set points of the UFLS program, to reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment is complete. These requirements were added to provide continuity on the requirement to assess UFLS program effectiveness for events since there is a similar requirement (with different applicable entities) currently in PRC-009-0, but PRC-009-0 is to be retired on approval of this standard. Do you agree with the addition of these requirements?

☐ Yes

☐ No

Comments:

14. The industry identified a need for a variance for the Québec Interconnection within NPCC to address the physical characteristics of the Québec system. This variance allows frequency decline to be arrested at a lower threshold and higher frequency overshoot without jeopardizing reliability because the installed generation in the Québec Interconnection is 98 percent hydraulic. The variance also establishes a different capacity threshold for the generating units for which underfrequency and overfrequency trip settings must be modeled to address concerns that by 2020, 10 percent of the installed capacity in Québec may be located at plants less than 75 MVA. The SDT has proposed the variance that meets the needs of the Québec interconnection in the third draft of the standard. In particular SDT developed the variance to Requirement R3 parts 3.1 and 3.2 and Requirement R4 parts 4.1 through 4.6. The variance to these requirements reference separate under and overfrequency curves included as attachments 1A and 2A to the standard. Do you agree with this Variance?

☐ Yes

☐ No

Comments:

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Implementation Plan for Under Frequency Load Shedding Reliability Standard

Prerequisite Approvals

With one exception, there are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Under Frequency Load Shedding standard and any associated regional reliability standards can be implemented. Parts 4.1 and 4.2 of Requirement R4 of the Under Frequency Load Shedding standard shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

Proposed Effective Date

Compliance with the new version PRC-006-1 — Underfrequency Load Shedding reliability standard is effective one year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required). The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time to develop or modify UFLS programs and to establish a schedule for implementation.

Compliance with the revised EOP-003-1 — Load Shedding Plans reliability standard is effective one year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

Applicability

Certain requirements within the proposed standard are intended to apply only to entities that own or operate UFLS relays. These requirements would not apply to other entities. The drafting team has designated these entities that own or operate UFLS relays as "UFLS Entities." They may include the following:

- Transmission Owners
- Distribution Providers

For decades underfrequency load shedding programs have been implemented by different entities depending on how the transmission system was constructed and owned. In some parts of the country, Distribution Providers accomplished this task, in others it was the Transmission Owners. Indeed, the set of standards intended to be replaced by this new standard allowed either of these registered entities, along with others in some cases, to accomplish the task of owning and operating UFLS relays. Because of this historical nature of the entities involved in the implementation of UFLS programs, and as listed in the applicability listed in the standards PRC-007-0 and PRC-009-0 that this standard is intended to replace, each of the functions listed above will have a role in implementing UFLS programs.

Retired Standards

The following standards will be retired when PRC-006-1 becomes effective:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-009-0 — UFLS Performance Following an Underfrequency Event will be completely retired once PRC-006-1 becomes effective as specified above.

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Proposed Effective Date

Compliance with the new version PRC-006-1 — Underfrequency Load Shedding reliability standard is effective one year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required). The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time to develop or modify UFLS programs and to establish a schedule for implementation.

Compliance with the revised EOP-003-1 — Load Shedding Plans reliability standard is effective one year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

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For decades underfrequency load shedding programs have been implemented by different entities depending on how the transmission system was constructed and owned. In some parts of the country, Distribution Providers accomplished this task, in others it was the Transmission Owners. Indeed, the set of standards intended to be replaced by this new standard allowed either of these registered entities, along with others in some cases, to accomplish the task of owning and operating UFLS relays. Because of this historical nature of the entities involved in the implementation of UFLS programs, and as listed in the applicability listed in the standards PRC-007-0 and PRC-009-0 that this standard is intended to replace, each of the functions listed above will have a role in implementing UFLS programs.

Retired Standards

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The following standards will be retired when PRC-006-1 becomes effective:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-009-0 — UFLS Performance Following an Underfrequency Event will be completely retired once PRC-006-1 becomes effective as specified above.

A. Introduction

1. Title: **Load Shedding Plans**

2. Number: EOP-003-1

3. Purpose: A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. Applicability:

4.1. Transmission Operators.

4.2. Balancing Authorities.

5. Effective Date: One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

R1/R3 Because this requirement is related to manual load shedding in addition to automatic load shedding, the drafting team did not modify the requirement. The UFLS standard is a planning standard and proposes requirements for automatic UFLS programs.

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2 The SDT reviewed R2 and thinks the original intent is to allow the TOP and BA to have a UFLS OR a UVLS program. If UFLS is deleted the original intent is modified such that the TOP has to have a UVLS program. This is why the SDT decided to add the additional language to the requirement. BA was deleted from the requirement because they are not responsible for voltage.

R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator shall consider one or more of these factors in designing an automatic load shedding scheme: voltage level, rate of voltage decay, or power flow levels.

R4 BA was deleted from the requirement because they are not responsible for voltage and references to items to consider for UFLS were deleted.

R5. A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions

R7 BA was deleted from the requirement because they are not responsible for voltage and "undervoltage" was added in the requirement because the TOP will have UFLS in its area and they should not be responsible for coordinating.

R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

M1. Each Transmission Operator that has or directs the deployment of undervoltage load shedding facilities, shall have and provide upon request, its automatic load shedding plans.(Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring Period and Reset Timeframe

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
R2	N/A	N/A	N/A	The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.
R3.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
R4.	N/A	N/A	N/A	The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.
R5.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
R7.	The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.
R8.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Load Shedding Plans**

2. **Number:** EOP-003-1

3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date:** One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rathe than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator ~~and Balancing Authority~~ shall establish plans for automatic load shedding for ~~underfrequency or~~ undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator ~~or Balancing Authority~~ shall consider one or more of these factors designing an automatic load shedding scheme: ~~frequency, rate of frequency decay,~~ voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator ~~and Balancing Authority~~ shall coordinate automatic undervoltage load shedding throughout their areas with ~~underfrequency isolation of generating units,~~ tripping of shunt capacitors, and other automatic actions that will occur under abnormal ~~frequency,~~ voltage, or power flow conditions

~~R6.~~**R8.** Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

R1/R3 Because this requirement is related to manual load shedding in addition to automatic load shedding, the drafting team did not modify the requirement. The UFLS standard is a planning standard and proposes requirements for automatic UFLS programs.

R2 The SDT reviewed R2 and thinks the original intent is to allow the TOP and BA to have a UFLS OR a UVLS program. If UFLS is deleted the original intent is modified such that the TOP has to have a UVLS program. This is why the SDT decided to add the additional language to the requirement. BA was deleted from the requirement because they are not responsible for voltage.

R4 BA was deleted from the requirement because they are not responsible for voltage and references to items to consider for UFLS were deleted.

R7 BA was deleted from the requirement because they are not responsible for voltage and "undervoltage" was added in the requirement because the TOP will have UFLS in its area and they should not be responsible for coordinating.

C. Measures

M1. Each Transmission Operator ~~and Balancing Authority~~ that has or directs the deployment of undervoltage ~~and/or underfrequency~~ load shedding facilities, shall have and provide upon request, its automatic load shedding plans.(Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring Period and Reset Timeframe

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~The Performance-Reset Period shall be 12 months from the last finding of noncompliance.~~

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
R2	N/A	N/A	N/A	The Transmission Operator ~~responsible entity~~ did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.
R3.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
R4.	N/A	N/A	N/A	The Transmission Operator ~~responsible entity~~ failed to consider at least one of the ~~five~~ three elements ~~(frequency, rate of frequency decay,~~voltage level, rate of voltage decay, or power flow levels) listed in the requirement.
R5.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.
R6.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
R7.	The Transmission Operator ~~responsible entity~~ did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement. ~~Coordination with individual generating units is considered as one automatic action for purposes of determining Violation Severity Levels.~~	The Transmission Operator ~~responsible entity~~ did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement. ~~Coordination with individual generating units is considered as one automatic action for purposes of determining Violation Severity Levels.~~	The Transmission Operator ~~responsible entity~~ did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement. ~~Coordination with individual generating units is considered as one automatic action for purposes of determining Violation Severity Levels.~~	The Transmission Operator ~~responsible entity~~ did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement. ~~Coordination with individual generating units is considered as one automatic action for purposes of determining Violation Severity Levels.~~
R8.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				shedding, as directed by the requirement.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on November 21, 2006.
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting Team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard, and posts for comments on April 15, 2009.

Proposed Action Plan and Description of Current Draft:

This is the third posting of the proposed standard

Future Development Plan:

Anticipated Actions	Anticipated Date
1. TBD	

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-1

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.3 Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **(Proposed) Effective Date:** The standard is effective the first day of the first calendar quarter one year after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter one year after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints that may form islands. *[VRF: Lower][Time Horizon: Long-term Planning]*

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity footprint or the Interconnection in which the Planning Coordinator's footprint resides. If a Planning Coordinator's footprint resides in multiple

Regional Entity footprints, each of those Regional Entity footprints shall be identified as an island

R3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its footprint that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 2, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R5. Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by any one Planning Coordinator that encompass more than one Planning Coordinator footprint. *[VRF: Medium][Time Horizon: Long-term Planning]*

R6. Each Planning Coordinator shall annually maintain a UFLS database for use in event analyses and assessments of the UFLS program. *[VRF: Lower][Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall provide its UFLS database to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. [VRF: Lower Time Horizon: Long-term Planning]

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

R10. Each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

R11. Each Planning Coordinator, in whose footprint a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

R13. Each Planning Coordinator, in whose footprint a BES islanding event affecting multiple Planning Coordinator footprints and resulting in system frequency excursions below the initializing set points of the UFLS program of UFLS actuated loss of load occurs, shall reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment completion. *[VRF: Medium][Time Horizon: Operations Assessment]*

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2 Parts 2.1 through 2.3 including the criteria itself.

M3. Each Planning Coordinator shall have evidence such as reports, program plans, or other documentation of its UFLS program including the implementation schedule that meet the criteria in Requirement R3 Parts 3.1 through 3.3 including the criteria itself.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4 Parts 4.1 through 4.7.

M5. Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any islands identified by a Planning Coordinator that encompass more than one Planning Coordinator footprint per Requirement R5 and identifies the affected Planning Coordinators.

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it annually maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6.

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning

Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of Facilities in accordance with the UFLS program and schedule for application per Requirement R10.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

M12. If UFLS program deficiencies are identified in R11, each Planning Coordinator shall have dated evidence that it conducted a UFLS design assessment per Requirements R12 and R4.

M13. Each Planning Coordinator shall dated have evidence such as letters, memorandums, or other dated documentation showing that each affected Planning Coordinator reached concurrence on the event assessment results per Requirement R13.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5 and R12, Measures M1, M2, M3, M4, M5 and M12 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.

- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11 and R13, Measures M11 and M13, for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, that may form islands OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, that may form islands	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, that may form islands	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, that may form islands
R2	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in 2.1, 2.2 or 2.3	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the parts as specified in 2.1, 2.2 or 2.3	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in 2.1, 2.2 or 2.3 OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its footprint, but failed to meet one (1) of the performance characteristic in Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its footprint, but failed to meet two (2) of the performance characteristic in Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its footprint, but failed to meet all the performance characteristic in Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	**N/A**	The Planning Coordinator failed reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by any one Planning Coordinator that encompass more than one Planning Coordinator footprint.
R6	N/A	N/A	N/A	The Planning Coordinator failed to annually maintain a UFLS database for use in event analyses and assessments of the UFLS program.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.		The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) footprint in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) footprint in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) footprint in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) footprint in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission	The Transmission Owner provided less than 85% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission
R11	Each Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one	The Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in	The Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in	The Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	year of event actuation to evaluate	11.1 and 11.2 greater than one year but less than or equal to 13 months of actuation.	11.1 and 11.2 greater than 13 months but less than or equal to 14 months of actuation. OR The Planning Coordinator, in whose footprint an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation but failed to evaluate one (1) of the parts as specified in 11.1 or 11.2.	11.1 and 11.2 greater than 14 months of actuation. OR The Planning Coordinator, in whose footprint an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluated the parts as specified in 11.1 and 11.2. OR The Planning Coordinator, in whose footprint an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation but failed to evaluate all of the parts as specified in 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per R11, failed to conduct

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose footprint a BES islanding event affecting multiple Planning Coordinator footprints and resulting in system frequency excursions below the initializing set points of the UFLS program, failed to reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment completion.

E. Regional Variances

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its footprint, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E3.1 Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, and

E3.2 Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 2A, and

E3.3 Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E3.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

E3.3.2 Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

E3.3.3 Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

E4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

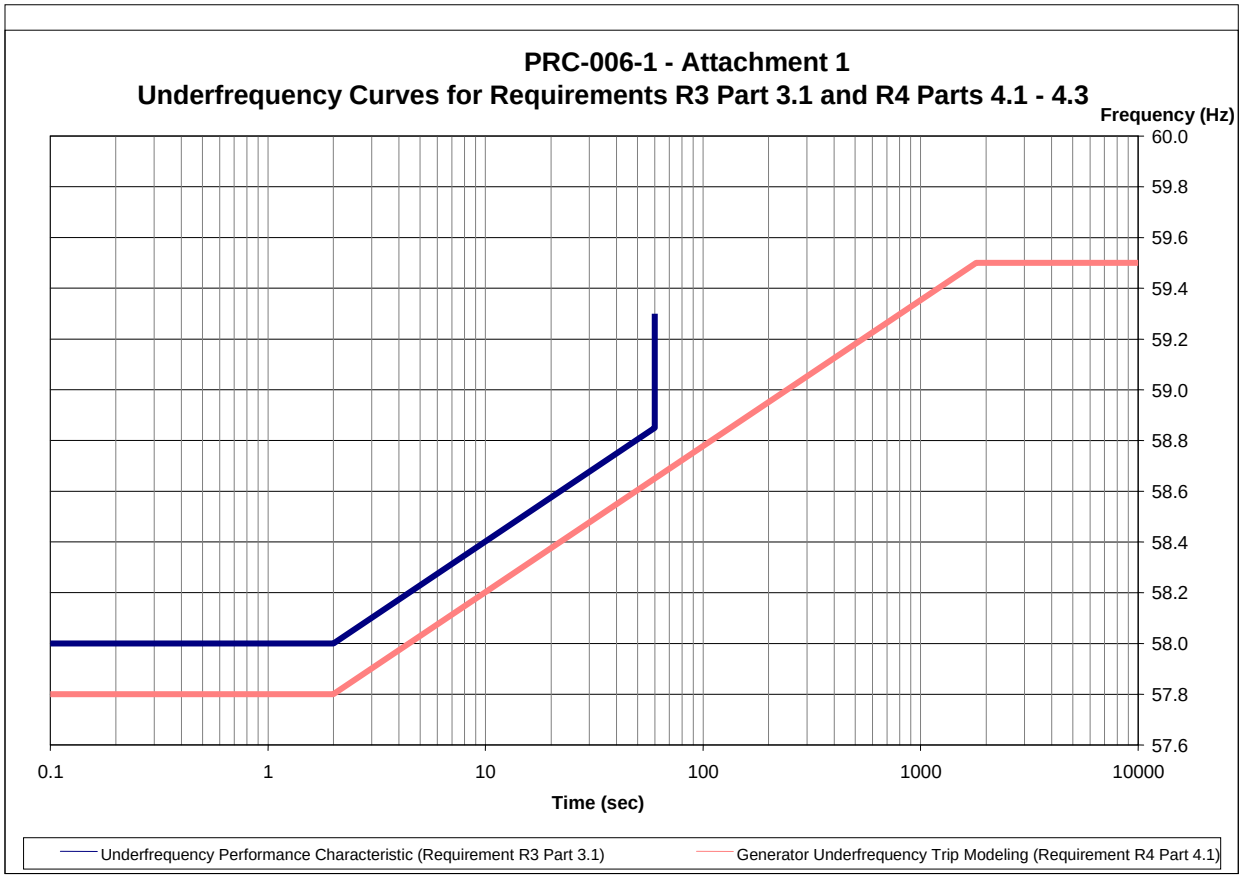
E4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

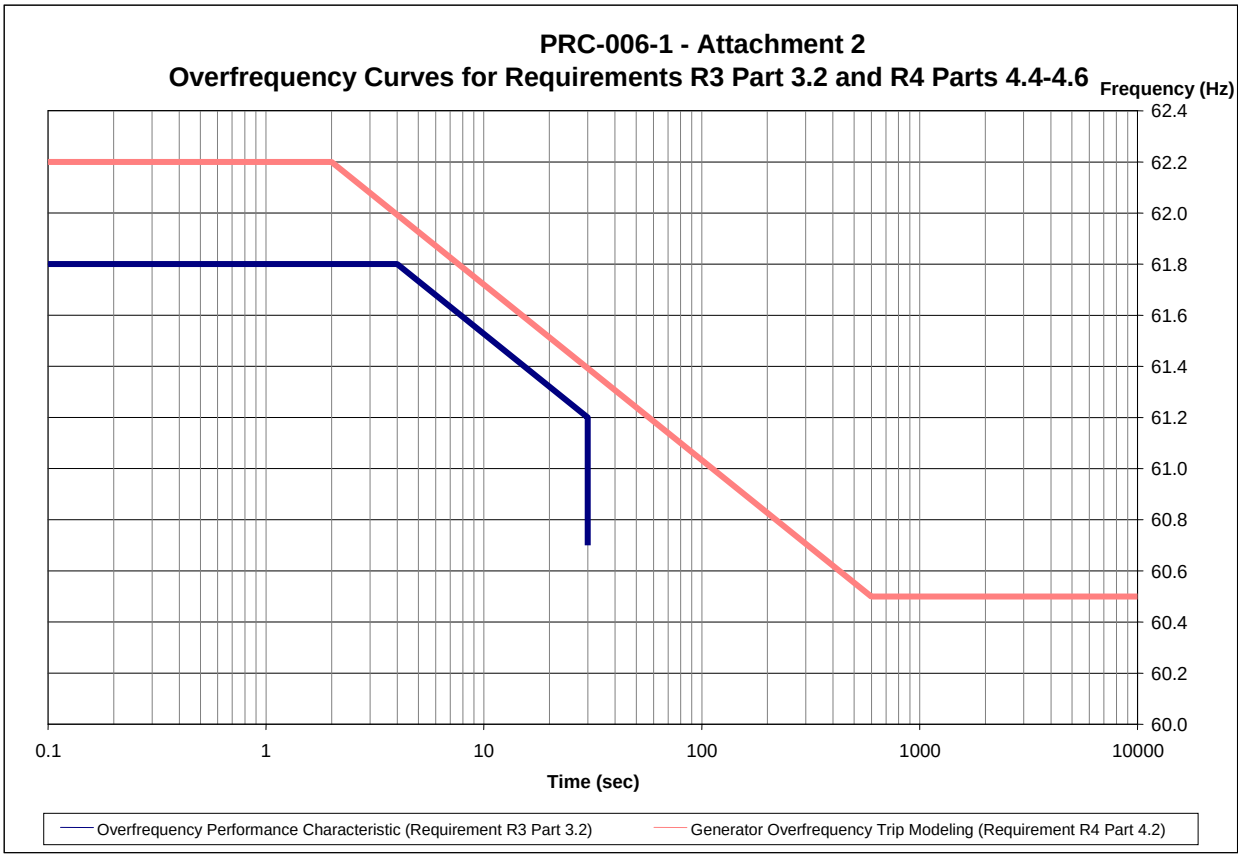
V #	Lower VSL	Moderate VSL	High VSL	Severe VSL
VE3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its footprint, but failed to meet one (1) of the performance characteristic in Parts E3.1, E3.2, or E3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its footprint, but failed to meet two (2) of the performance characteristic in Parts E3.1, E3.2, or E3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its footprint, but failed to meet all the performance characteristic in Parts E3.1, E3.2, and E3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
VE4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include one (1) of the items as specified in Parts E4.1, E4.2 or E4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E4.1, E4.2 or E4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E4.1, E4.2 and E4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3

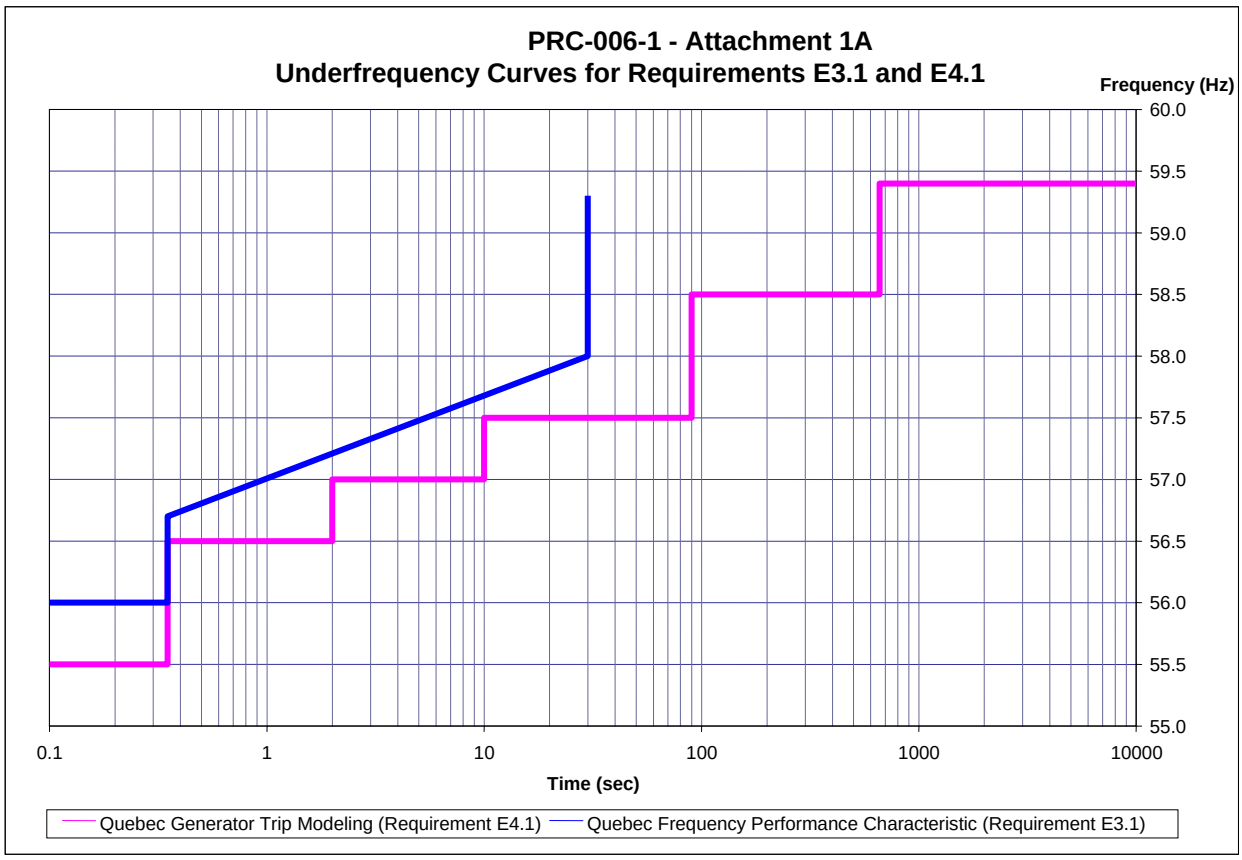
F. Associated Documents

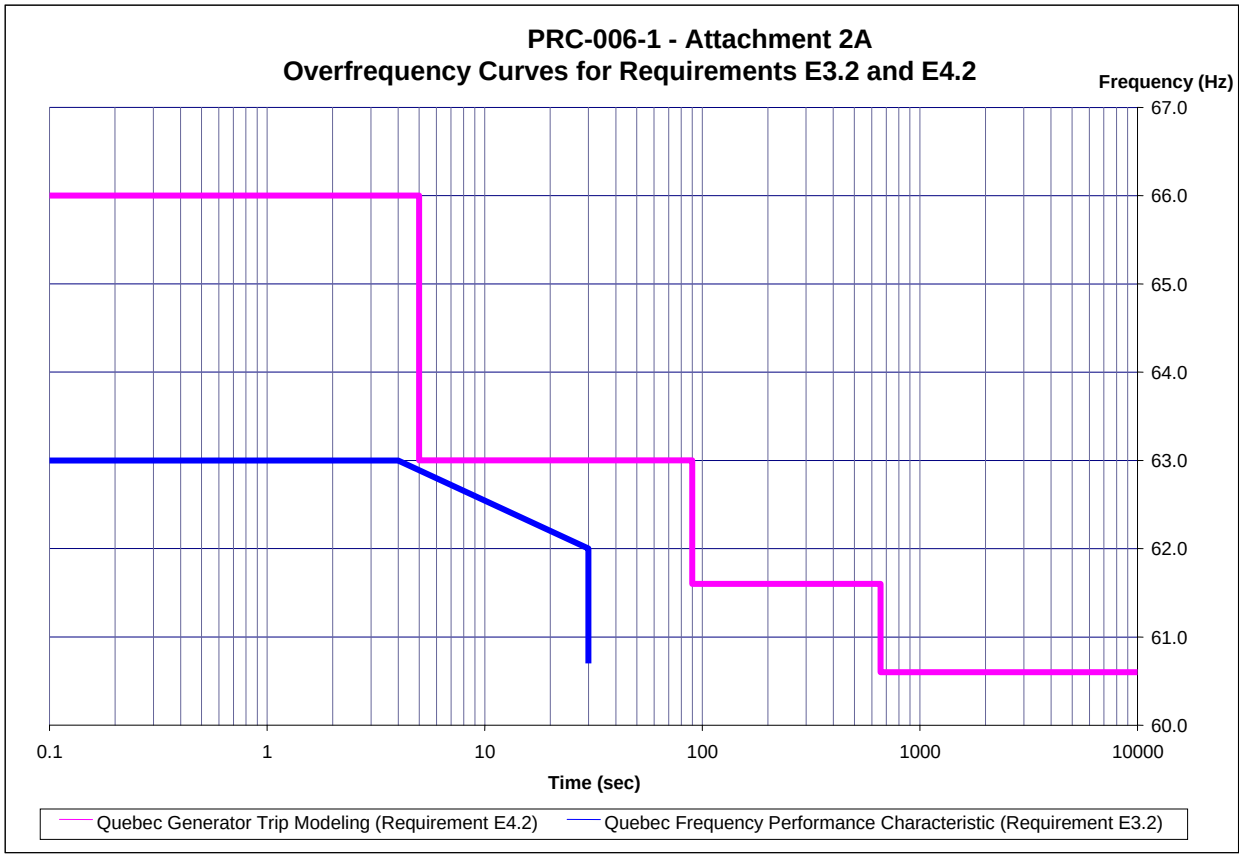
Version History

Version	Date	Action	Change Tracking
1		Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0	


PRC-006-1 - Attachment 1
Underfrequency Curves for Requirements R3 Part 3.1 and R4 Parts 4.1 - 4.3
Frequency (Hz)
60.0
59.8
59.6
59.4
59.2
59.0
58.8
58.6
58.4
58.2
58.0
57.8
57.6
0.1
1
10
100
1000
10000
Time (sec)
Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
Generator Underfrequency Trip Modeling (Requirement R4 Part 4.1)


PRC-006-1 - Attachment 2
Overfrequency Curves for Requirements R3 Part 3.2 and R4 Parts 4.4-4.6
Frequency (Hz)
62.4
62.2
62.0
61.8
61.6
61.4
61.2
61.0
60.8
60.6
60.4
60.2
60.0
0.1
1
10
100
1000
10000
Time (sec)
Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
Generator Overfrequency Trip Modeling (Requirement R4 Part 4.2)


PRC-006-1 - Attachment 1A
Underfrequency Curves for Requirements E3.1 and E4.1
Frequency (Hz)
60.0
59.5
59.0
58.5
58.0
57.5
57.0
56.5
56.0
55.5
55.0
0.1
1
10
100
1000
10000
Time (sec)
Quebec Generator Trip Modeling (Requirement E4.1)
Quebec Frequency Performance Characteristic (Requirement E3.1)


PRC-006-1 - Attachment 2A
Overfrequency Curves for Requirements E3.2 and E4.2
Frequency (Hz)
67.0
66.0
65.0
64.0
63.0
62.0
61.0
60.0
0.1
1
10
100
1000
10000
Time (sec)
Quebec Generator Trip Modeling (Requirement E4.2)
Quebec Frequency Performance Characteristic (Requirement E3.2)

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on November 21, 2006.
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting Team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard, and posts for comments on April 15, 2009.

Proposed Action Plan and Description of Current Draft:

This is the third posting of the proposed standard

Future Development Plan:

Anticipated Actions	Anticipated Date
1. TBD	

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-011

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   1.1.4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.3 Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load that own Elements identified in the UFLS program established by the Planning Coordinators.

2. **(Proposed) Effective Date:** TBD

5. **(Proposed) Effective Date:** The standard is effective the first day of the first calendar quarter one year after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter one year after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Each Planning Coordinator shall join a group consisting of all the Planning Coordinators within the region for each of the regions in which it performs the Planning Coordinator function.

R2. Each group of Planning Coordinators shall design an underfrequency load shedding program for consistent application across the region.

R3.**R1.** Each group of Planning Coordinators shall develop and document criteria, consideringincluding consideration of historical events and system studies, to select portions of the Bulk Electric System (BES)), including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints that may form islands. *[VRF: Lower][Time Horizon: Long-term Planning]*

R3. Each group of Planning CoordinatorsCoordinator shall develop a procedure for coordinating with groups of Planning Coordinators in neighboring regions within an interconnection to identify and reach agreement onone or more islands between its region and neighboring regions within the interconnection. The procedure shall identify

how the neighboring entities will assist in the UFLS assessments and document concurrence of assessment results.

R5. **R2.** Each group of Planning Coordinators shall identify an island(s) to serve as a basis for designing a its UFLS program. The identified island(s) shall include: including: *[VRF: Medium][Time Horizon: Long-term Planning]*

- **2.1.** Those islands selected by applying the criteria in Requirement R3, if any. R1, and
- **2.2.** Any portions of the BES that are designed to be detached detach from the interconnection Interconnection (planned islands) as a result of the operation of a relay scheme. or Special Protection System, and
- Interregional islands agreed on by the Planning Coordinators.
- Any other islands necessary to ensure that all portions of the region's BES are included in at least one island.

2.3. Each group of Planning Coordinators shall specify the technical design parameters of the underfrequency load shedding program required to meet A single island that includes all portions of the BES in either the Regional Entity footprint or the Interconnection in which the Planning Coordinator's footprint resides. If a Planning Coordinator's footprint resides in multiple Regional Entity footprints, each of those Regional Entity footprints shall be identified as an island

R6. **R3.** Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its footprint that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load – actual generation output) / (load)])], of up to 25 percent within the identified island(s):). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Arrest frequency decline at no less than 58.0 Hz.

3.1. Frequency shall not remain below 58.2 Hz for greater than four seconds cumulatively per simulated event above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, and

R6.2.3.2. Frequency shall not remain below 58.5 Hz for greater than ten seconds cumulatively per simulated event the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 2, and shall not remain below 59.3 Hz for greater than 30 seconds, cumulatively per simulated event.

3.3. Frequency overshoot resulting from operation of UFLS relays shall not exceed 61.8 Hz for any duration and shall not exceed 60.7 Hz for greater than 30 seconds, cumulatively per simulated event.

R6.4.3.3. Control voltage during and following UFLS operations such that the per unit Volts per Hz (V/Hz) does shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and does shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each

generator bus and generator step-up transformer high-side bus associated with any:each of the following:

R6.4.1.3.3.1. Individual generating unitunits greater than 20 MVA (gross nameplate rating) and directly connected to the BES.

R6.4.2.3.3.2. Generating plant/facilityplants/facilities greater than 75 MVA (gross aggregate nameplate rating) and directly connected to the BES.

3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

R7.R4. Each group of Planning CoordinatorsCoordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R6.R3 for each island identified in Requirement R2. The simulation shall include;model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

3.5. Modeling the trip settings of any generators that trip at or above 58.0 Hz.

3.6. Modeling the trip settings of any generators that trip at or below 61.8 Hz.

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling any curve in PRC-006-1 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

R7.3.4.7. Any automatic load Load restoration that is designed to assist in stabilizingimpacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R5. Each group ofEach Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by any one Planning Coordinator that encompass more than one Planning Coordinator footprint. *[VRF: Medium][Time Horizon: Long-term Planning]*

R8.**R6.** Each Planning Coordinator shall create and annually maintain a UFLS database containing relay information provided by their Transmission Owners and Distribution Providers for for use in UFLS assessments and event analyses. and assessments of the UFLS program. *[VRF: Lower][Time Horizon: Long-term Planning]*

R7. Each Transmission Owner and Distribution ProviderEach Planning Coordinator shall provide its UFLS database to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

R9.**R8.** Each UFLS entity shall provide data to its group of Planning Coordinators Coordinator(s) according to the format and schedule and format specified by the group of Planning Coordinators Coordinator(s) to support maintenance of the database. each Planning Coordinator's UFLS database. [VRF: Lower Time Horizon: Long-term Planning]

R9. Each Transmission Owner and Distribution ProviderUFLS entity shall provide load automatic tripping of Load in accordance with the UFLS program designeddesign and schedule for application determined by the group ofits Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

R10. Each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

R11. Each Planning Coordinator, in whose footprint a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

R13. Each Planning Coordinator, in whose footprint a BES islanding event affecting multiple Planning Coordinator footprints and resulting in system frequency excursions

below the initializing set points of the UFLS program of UFLS actuated loss of load occurs, shall reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment completion. *[VRF: Medium][Time Horizon: Operations Assessment]*

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2 Parts 2.1 through 2.3 including the criteria itself.

M3. Each Planning Coordinator shall have evidence such as reports, program plans, or other documentation of its UFLS program including the implementation schedule that meet the criteria in Requirement R3 Parts 3.1 through 3.3 including the criteria itself.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4 Parts 4.1 through 4.7.

~~R10.~~**M5.** Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators ~~for each region in which it operates~~on design assessment results for any islands identified by a Planning Coordinator that encompass more than one Planning Coordinator footprint per Requirement R5 and identifies the affected Planning Coordinators.

~~M1.~~**M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it annually maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6.

~~M2.~~**M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

~~M3.~~**M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

~~M4.~~**M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay

settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

~~M5.~~M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of Facilities in accordance with the UFLS program and schedule for application per Requirement R10.

~~M6.~~M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

~~M7.~~M12. If UFLS program deficiencies are identified in R11, each Planning Coordinator shall have dated evidence that it conducted a UFLS design assessment per Requirements R12 and R4.

~~M8.~~M13. Each Planning Coordinator shall dated have evidence such as letters, memorandums, or other dated documentation showing that each affected Planning Coordinator reached concurrence on the event assessment results per Requirement R13.

~~C.~~D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5 and R12, Measures M1, M2, M3, M4, M5 and M12 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.

- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11 and R13, Measures M11 and M13, for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, that may form islands OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, that may form islands	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, that may form islands	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, that may form islands
R2	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in 2.1, 2.2 or 2.3	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the parts as specified in 2.1, 2.2 or 2.3	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in 2.1, 2.2 or 2.3 OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.

R #		Lower VSL	Moderate VSL	High VSL	Severe VSL
R3		N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its footprint, but failed to meet one (1) of the performance characteristic in Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its footprint, but failed to meet two (2) of the performance characteristic in Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its footprint, but failed to meet all the performance characteristic in Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
R4		The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	**N/A**	The Planning Coordinator failed reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by any one Planning Coordinator that encompass more than one Planning Coordinator footprint.
R6	N/A	N/A	N/A	The Planning Coordinator failed to annually maintain a UFLS database for use in event analyses and assessments of the UFLS program.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.		The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) footprint in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) footprint in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) footprint in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) footprint in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission	The Transmission Owner provided less than 85% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission
R11	Each Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one	The Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in	The Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in	The Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	year of event actuation to evaluate	11.1 and 11.2 greater than one year but less than or equal to 13 months of actuation.	11.1 and 11.2 greater than 13 months but less than or equal to 14 months of actuation. OR The Planning Coordinator, in whose footprint an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation but failed to evaluate one (1) of the parts as specified in 11.1 or 11.2.	11.1 and 11.2 greater than 14 months of actuation. OR The Planning Coordinator, in whose footprint an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluated the parts as specified in 11.1 and 11.2. OR The Planning Coordinator, in whose footprint an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation but failed to evaluate all of the parts as specified in 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per R11, failed to conduct

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose footprint a BES islanding event affecting multiple Planning Coordinator footprints and resulting in system frequency excursions below the initializing set points of the UFLS program, failed to reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment completion.

~~D.~~E. Regional Variances

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its footprint, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E3.1 Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, and

E3.2 Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 2A, and

E3.3 Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E3.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

E3.3.2 Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

E3.3.3 Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

E4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

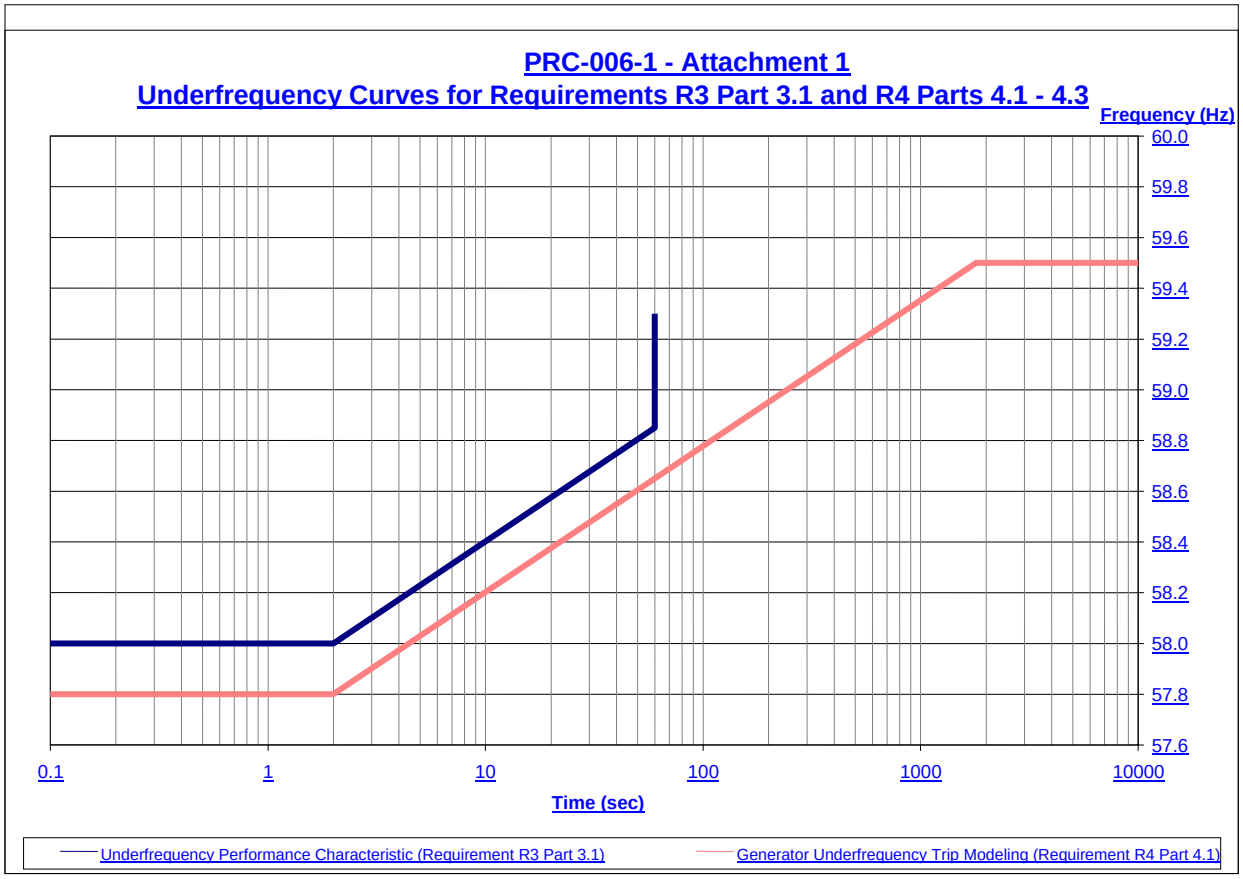
E4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

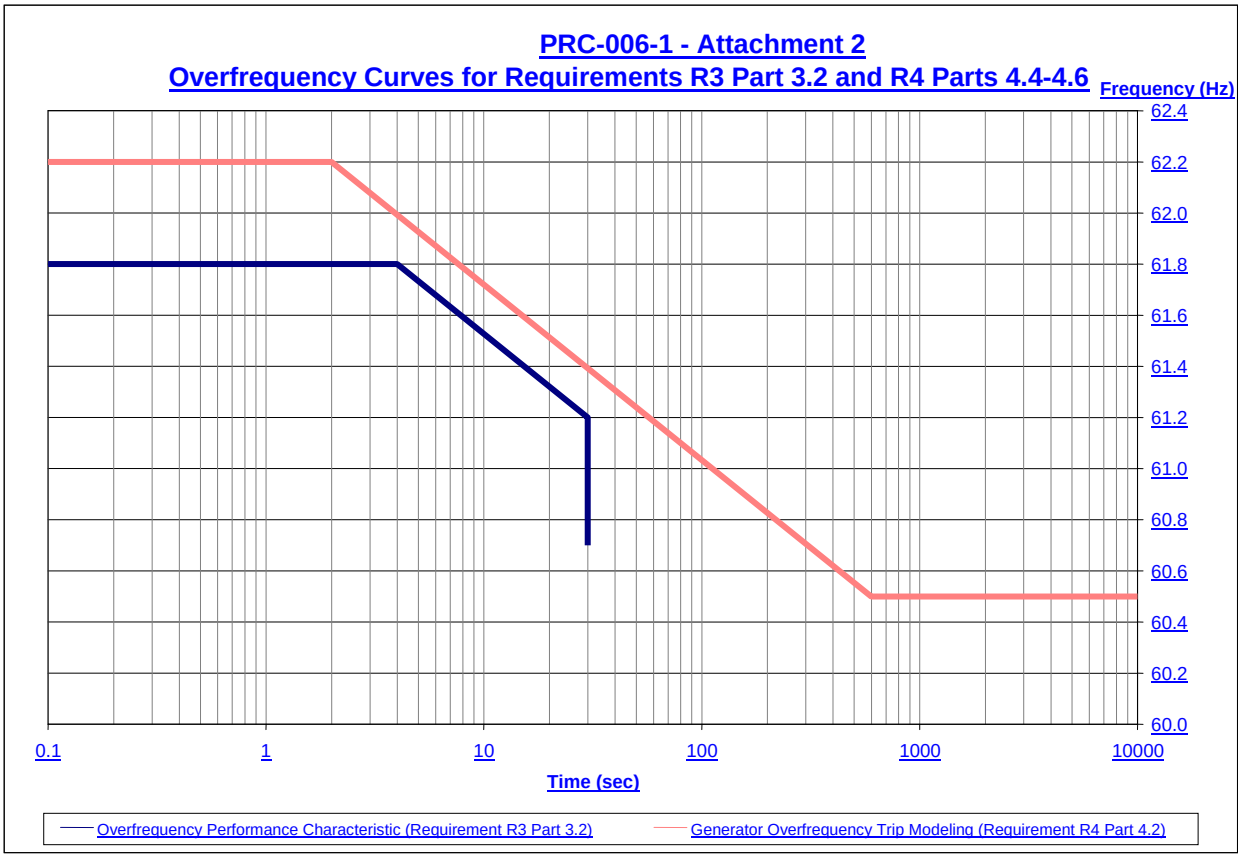
V #	Lower VSL	Moderate VSL	High VSL	Severe VSL
VE3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its footprint, but failed to meet one (1) of the performance characteristic in Parts E3.1, E3.2, or E3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its footprint, but failed to meet two (2) of the performance characteristic in Parts E3.1, E3.2, or E3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its footprint, but failed to meet all the performance characteristic in Parts E3.1, E3.2, and E3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
VE4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include one (1) of the items as specified in Parts E4.1, E4.2 or E4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E4.1, E4.2 or E4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E4.1, E4.2 and E4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3

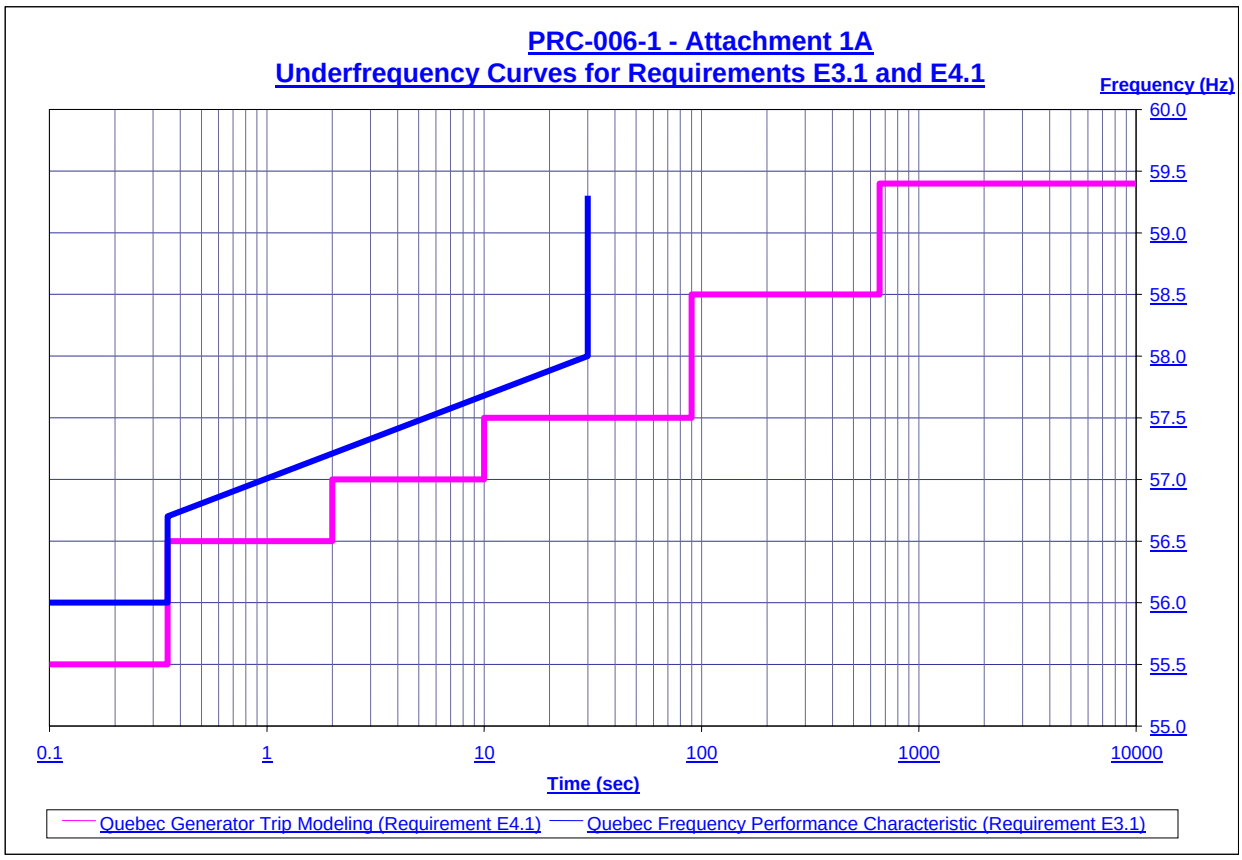
~~E.~~F. Associated Documents

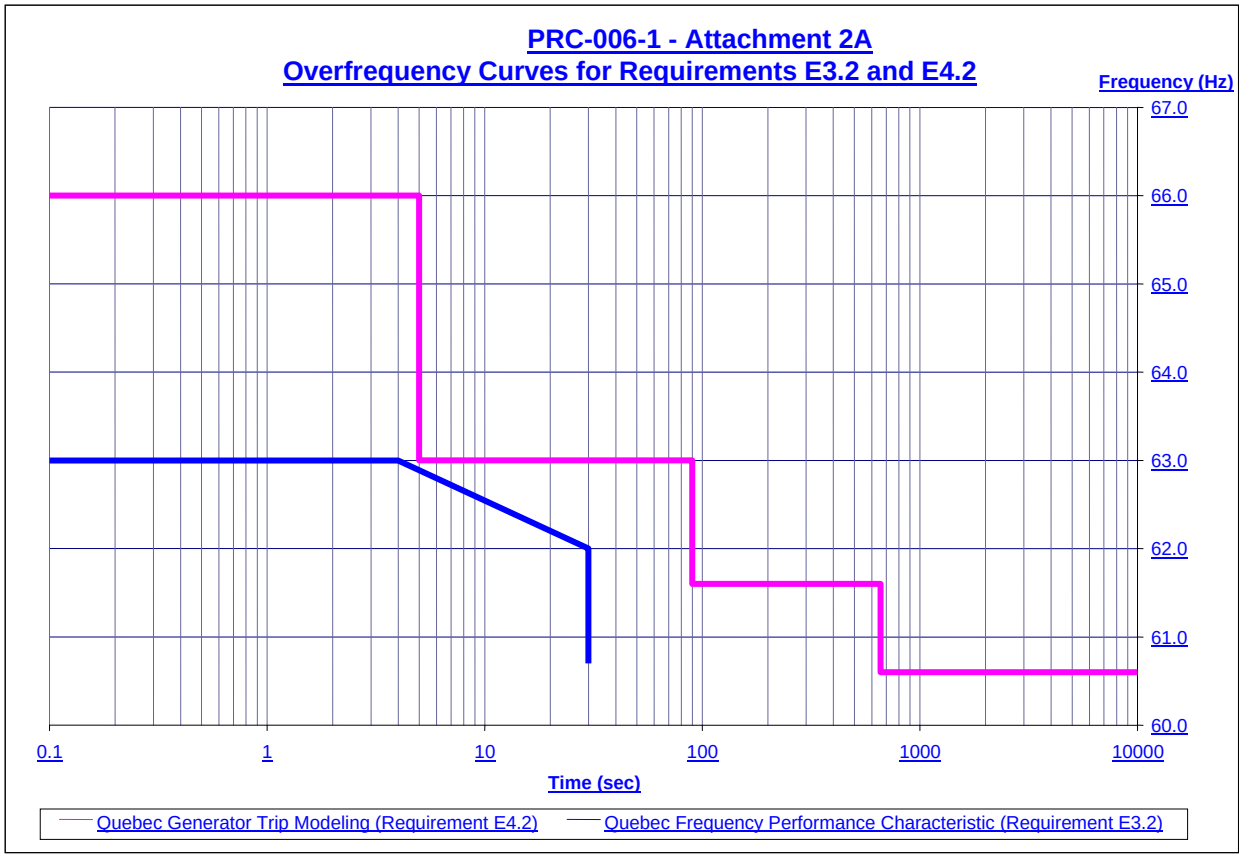
Version History

Version	Date	Action	Change Tracking
1		Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0	


PRC-006-1 - Attachment 1
Underfrequency Curves for Requirements R3 Part 3.1 and R4 Parts 4.1 - 4.3
Frequency (Hz)
60.0
59.8
59.6
59.4
59.2
59.0
58.8
58.6
58.4
58.2
58.0
57.8
57.6
0.1
1
10
100
1000
10000
Time (sec)
Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
Generator Underfrequency Trip Modeling (Requirement R4 Part 4.1)


PRC-006-1 - Attachment 2
Overfrequency Curves for Requirements R3 Part 3.2 and R4 Parts 4.4-4.6
Frequency (Hz)
62.4
62.2
62.0
61.8
61.6
61.4
61.2
61.0
60.8
60.6
60.4
60.2
60.0
0.1
1
10
100
1000
10000
Time (sec)
Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
Generator Overfrequency Trip Modeling (Requirement R4 Part 4.2)


PRC-006-1 - Attachment 1A
Underfrequency Curves for Requirements E3.1 and E4.1
Frequency (Hz)
60.0
59.5
59.0
58.5
58.0
57.5
57.0
56.5
56.0
55.5
55.0
0.1
1
10
100
1000
10000
Time (sec)
Quebec Generator Trip Modeling (Requirement E4.1)
Quebec Frequency Performance Characteristic (Requirement E3.1)


PRC-006-1 - Attachment 2A
Overfrequency Curves for Requirements E3.2 and E4.2
Frequency (Hz)
67.0
66.0
65.0
64.0
63.0
62.0
61.0
60.0
0.1
1
10
100
1000
10000
Time (sec)
Quebec Generator Trip Modeling (Requirement E4.2)
Quebec Frequency Performance Characteristic (Requirement E3.2)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Ballot Pool and Pre-ballot Window (with Comment Period)
Project 2007-01: Underfrequency Load Shedding

Now available at:
http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Project 2007-01: Underfrequency Load Shedding

On March 18, 2010, FERC issued several orders and notices of proposed rulemakings pertaining to standards development activities and processes, suggesting a lack of progress in responding to directives from Order 693 as well in the timeliness of standards development in general. At the May 2010 NERC Board meeting, Gerry Cauley, NERC's President, also expressed these concerns, indicating that the resolution to these concerns is one of NERC's top priorities in the near term. As a result, the Standards Committee has authorized deviations from the normal standards development process for the Underfrequency Load Shedding project, as well as other projects that have been through significant stakeholder review through the development process, to demonstrate that the NERC enterprise is responsive to FERC directives, and is making progress in developing new standards.

The Standards Committee approved the following deviations from the standards development process:

- The proposed changes to the standards will be posted for a 35-day comment period (rather than a 45-day comment period). The Ballot Pool will be formed during the first 21 days of the 35-day comment period;
- The initial ballot will be conducted during the last 10 days of the 35-day comment period; and
- The drafting team may make modifications between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the standard.

Ballot Pool (through July 2, 2010)

Registered Ballot Body members may join the ballot pool **until 8 a.m. Eastern on July 2, 2010** to be eligible to vote in the upcoming ballot at the following page: https://standards.nerc.net/BallotPool.aspx. Members who join the ballot pool to vote on the standard will automatically be entered in a separate pool to participate in the non-binding poll of the associated violation risk factors (VRFs) and violation severity levels (VSLs). (As a reminder, this new approach for VRFs and VSLs is one of the updates reflected in the recently FERC-approved Reliability Standards Development Procedure – Version 7.)

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2007-01_UFLS_in@nerc.com

Comment Period (through July 16, 2010)

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at 609-524-7047.

The status, purpose, a clean and redline version of the four standards, and supporting documents for this project — including an off-line, unofficial copy of the questions listed in the comment form — are posted at the following site: http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Project Background

Major objectives:

1. Ensure UFLS programs are developed to provide an appropriate level of reliability (not least common denominator).
2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.
3. Address the issues raised by FERC Order 693 and other applicable orders.
4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

Further details are available on the project page:
http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html.

Applicability of Standards in Project

- Planning Coordinators
- UFLS Entities — entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
  - Transmission Owners.
  - Distribution Providers.
- Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Lauren Koller at Lauren.Koller@nerc.net

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Standards Announcement

Ballot Pool and Pre-ballot Window (with Comment Period)
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Project 2007-01: Underfrequency Load Shedding

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The Standards Committee approved the following deviations from the standards development process:

- The proposed changes to the standards will be posted for a 35-day comment period (rather than a 45-day comment period). The Ballot Pool will be formed during the first 21 days of the 35-day comment period;
- The initial ballot will be conducted during the last 10 days of the 35-day comment period; and
- The drafting team may make modifications between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the standard.

Ballot Pool (through July 2, 2010)

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During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2007-01_UFLS_in@nerc.com

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Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at 609-524-7047.

The status, purpose, a clean and redline version of the four standards, and supporting documents for this project — including an off-line, unofficial copy of the questions listed in the comment form — are posted at the following site: http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Project Background

Major objectives:

1. Ensure UFLS programs are developed to provide an appropriate level of reliability (not least common denominator).
2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.
3. Address the issues raised by FERC Order 693 and other applicable orders.
4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

Further details are available on the project page:
http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html.

Applicability of Standards in Project

- Planning Coordinators
- UFLS Entities — entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
  - Transmission Owners.
  - Distribution Providers.
- Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Lauren Koller at Lauren.Koller@nerc.net

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Window Open

July 8-July 17, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2007-01: Underfrequency Load Shedding

An initial ballot window for proposed standards PRC-006-1 — Automatic Underfrequency Load Shedding and EOP-003-1— Load Shedding Plans is now open **until 8 p.m. Eastern on July 17, 2010.**

In addition to voting on the standard, members of the ballot pool will be able to vote in a concurrent non-binding poll for the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) associated with the standard. Members who joined the ballot pool to vote on the standard were automatically entered in a separate pool to participate in the non-binding poll for the VRFs and VSLs. The non-binding poll will appear in your list of current ballots, and is labeled accordingly. (As a reminder, this new approach for VRFs and VSLs is one of the updates reflected in the recently FERC-approved Reliability Standards Development Procedure — Version 7.)

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

Major objectives:

1. Ensure UFLS programs are developed to provide an appropriate level of reliability (not least common denominator).
2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.
3. Address the issues raised by FERC Order 693 and other applicable orders.
4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

Project page: http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Special Notes

On March 18, 2010, FERC issued several orders and notices of proposed rulemakings pertaining to standards development activities and processes, suggesting a lack of progress in responding to directives from Order 693 as well in the timeliness of standards development in general. At the May 2010 NERC Board meeting, Gerry Cauley, NERC's President, also expressed these concerns, indicating that the resolution to these concerns is one of NERC's top priorities in the near term. As a result, the Standards Committee has authorized deviations from the normal standards

development process for the Protection System Maintenance and Testing project, as well as other projects that have been through significant stakeholder review through the development process, to demonstrate that the NERC enterprise is responsive to FERC directives, and is making progress in developing new standards.

The Standards Committee approved the following deviations from the standards development process:

- The proposed changes to the standard and definition will be posted for 35-day comment periods (rather than 45-day comment periods). The ballot pools will be formed during the first 21 days of the 35-day comment periods;
- The initial ballots will be conducted during the last 10 days of the 35-day comment periods; and
- The drafting team may make modifications between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the standard and definition.

Applicability of Standards in Project

- Planning Coordinators
- UFLS Entities — entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
    - Transmission Owners.
    - Distribution Providers.
- Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Lauren Koller at Lauren.Koller@nerc.net

Individual or group. (41 Responses)
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Organization (25 Responses)
Group Name (16 Responses)
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Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
No
The VRF for R1 for the development and documentation of UFLS program criteria is stated as a Low VRF. Such a requirement to develop overall UFLS program criteria was more than a 'Low' or Administrative requirement, and the VRF for this requirement should be listed as a Medium VRF. The requirement to develop program criteria in Requirement R1 is as important as those requirements stated in Requirement R2 which was assigned a Medium VRF by the DT.
Yes
The Measures are logical and consistent with the corresponding requirements.
Yes
Yes

Yes
Yes
EOP 003 is on the list of standards identified by the NERC Tiger Team for fast tracking of Order 693 directives. There is concern that coordination between these two DT's may not have occurred and that the changes agreed upon in the revised UFLS SAR should also be considered by the Tiger Team.
No
Significant amounts of UFLS capability may fall outside the current FM design, and the DT is trying to capture all entities that control UFLS in its applicability requirements. In spite of this effort ambiguity still exists in the applicability regarding the broad statement pertaining to UFLS entities that 'control' UFLS equipment.
No
Although the DT's decision to replace the discrete points in these requirements with frequency time curves that achieve the same objective, the applicability requirement in Requirement R3.3, which addresses Volts per Hz performance characteristics, lists each generator bus and generator step-up transformer high-side bus associated with generating facilities defined in sub-requirements 3.3.1, 3.3.2, and 3.3.3. The facilities listed in the above sub-requirements appear to be quoted from the NERC Statement of Compliance Registry Criteria, Sections III.c.1 & III.c.2. It is not clear why sub requirement 3.3.3 is necessary since it is simply a restatement of requirement 3.3.2. Suggest that 3.3.3 be eliminated and that 3.3.2 be re-written to be consistent with the Registry, Section III.c.2, "Generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating."
No
Similar to the comment provided in response to Question 9, requirements 4.3 and 4.6 are simply restatements of requirements 4.2 and 4.5, respectively. Suggest that requirements 4.3 and 4.6 be eliminated, and that requirements 4.2 and 4.5 be rewritten to contain the language dealing with the applicability of composite facilities as defined in the Registry Criteria Section II.c.2. Additionally, this draft version of PRC-006 states in requirements 4.1 through 4.6 (as well as in requirements 3.3.1 through 3.3.3) that the assessment of non-conforming generator trip settings is limited to those generators generally defined by the Registry Criteria, rather than assuming that the Functional Entities shown in the Applicability Section of the Standard are further defined by the NERC Registry Criteria. This limitation is not necessarily valid for situations where any generator, regardless of size, is material to the reliability of the BES (Registry Criteria III.c.4). In particular during the development of a supporting Regional Standard it is quite possible that the amount of generation whose non-conforming performance characteristics may be tolerated, (and thus eliminated from assessment consideration), will be very limited. In regions where a great preponderance of the total generation is comprised of smaller units the tolerance threshold for ignoring generation below a bright line value defined by PRC-006 may invalidate conclusions of the Regional UFLS Program assessments. These conclusions presently demonstrate that the Regional Program meets the broad performance characteristics and/or requirements of PRC-006. The PRC-006 SDT should be aware that those RSDTs developing Regional Standards will, based on necessity, assess the applicability of Functional Entities and to the degree that a materiality issue is raised will bring that issue before the Regional Entity. Regional Entities would be expected to confirm that reliability is at stake prior to the issuance of a Compliance Guidance Statement, or other communication tool. The RSDT expects that the reach of applicability governing the registration and compliance obligations of any such Functional Entity identified under the "material to the reliability of the bulk power system" clause of the Registry Criteria will be clearly defined in each Regional Standard. Generation facilities which do not meet the NERC generator registration criteria could avoid obligations to meet generator underfrequency and overfrequency trip requirements presented in the standard. Significant amounts of generation categorized as such could cumulatively jeopardize the performance of a UFLS program. Possible future trends in the development of generation could increase the amount of installed generation capacity that does not meet the NERC generator registration criteria. Such trends may include the development of renewable distributed generation that is not connected to the BES system.
Yes
No
Limiting applicability to only the TO limits the thrust of this requirement in cases where other FM entities are responsible for switching of elements that support the UFLS program. The Drafting Team should consider modifying R4 to include a requirement to model any automatically switched elements related to a UFLS program. The Drafting Team should consider a requirement to inform the Planning Coordinator of the implementation of UFLS relay inhibit schemes (e.g. voltage inhibit) and any associated parameters. Knowledge of such information would be vital to

the Planning Coordinator when assessing the performance of a UFLS program.
No
At present, the language in the implementation plan describes a one year phase in for compliance intended to provide Planning Coordinators sufficient time to develop or modify UFLS programs and to establish a schedule for implementation. NPCC has already developed an implementation plan. It must be noted that the NPCC implementation plan is a six year plan and the final language of the NERC implementation plan with regard to the overall approved term will have be closely monitored.
Yes
Individual
James Sharpe
South Carolina Electric and Gas
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
The graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curves data points.
Yes
Yes
Yes
Yes
Yes
Individual
John Bee
Exelon
Yes
No
Exelon does not agree with the concept of allowing neighboring Planning Coordinators to define or modify islanding criteria. There should be a single criteria for the determination of an island which is consistent across the interconnection, unless a specific geographic or regional exception is identified. Even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint.
Yes

No
Exelon does not agree with the concept of allowing neighboring Planning Coordinators to define or modify islanding criteria. There should be a single criteria for the determination of an island which is consistent across the interconnection, unless a specific geographic or regional exception is identified. Even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint.
Yes
Yes
No
EOP-003-1 needs to define the criteria as to when and how UVLS schemes are installed to provide consistency direction to Planning Coordinators and the entities that have to install UVLS schemes. The relationship between the use of UVLS and compliance with TPL-001 standards should be clarified. Is load shedding (including UVLS) allowed to meet the performance criteria in TPL-001? The standard should define when UVLS are applicable to the BES and thus subject to the requirements of EOP-003. UVLS schemes developed for distribution or other purposes beyond criteria should not be discouraged through regulatory burden. UVLS should be carefully defined. Many types of load will cut out on low voltage.
Yes
No
The standard lacks guidance as to what the trip settings should be. It is not clear as to how Attachment 1 should be used and doesn't provide specific detail for under frequency set points. Exelon disagrees that R3.3 is easier to understand. Clarification is needed as to where the underfrequency set points are. Do all entities contribute equally to Attachment 1? There needs to be a standardized relationship between GO and TO/DP participation in obtaining the desired level of system performance. There should also be explicit criteria as to what the expectations are for each individual entity. It should be clear that all UFLS entities are to participate equally and that larger entities will not be expected to carry the burden for smaller entities. There should be some recognition in the standard that UFLS schemes currently exist and effort should be made to avoid needlessly changing relays or settings on many thousands of installations if some arbitrary and common set points were to be determined by the PC, thus causing needless expense. It is likely desireable to have slightly different settings for UFLS across a footprint so as to not create load changes that are too abrupt. The current practice of allowing contractual agreements between GOs and DPs for additional load shedding as a voluntary business decision, in the event that a unit owner doesn't comply with the unit trip settings should be addressed.
No
Exelon feels that a table should be included with the curves. What was the source of the curves and the V/Hz requirements? The table seems to indicate that it is acceptable for the Eastern Interconnection to remain at 58.9 Hz for up to one minute. The data requirements for the assessment study should include additional data other than that for units out of compliance, i.e. all loads for the entire system as load is dropping.
No
Exelons concern is that neighboring Planning Coordinators will be making requests and setting criteria for the local planning coordinators and associated UFLS entities. We do not agree with the text "any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating."
Yes
Yes
Yes
Individual
Ernesto Paon
MEAG Power
Yes
Yes

No
Developing a VSL tool similar to the VRF tool would be beneficial. The VSL seem arbitrary. For example, R1 has a "moderate" and "high" VSL if you do not take into account historical events when documenting and developing the criteria, but what if your sub-region never had an UF event? You are still in compliance?
Yes
Yes
Yes
No comment.
Yes
This is an excellent language change.
Yes
Yes
Yes
No
What are automatic switching of elements? Does it mean that the TO needs to switch capacitor banks, or does it refer to the breakers equipped with UF relays? If it is referring to capacitor banks, is this applicable near major generation busses?
Yes
No comment.
Individual
Kirit Shah
Ameren
Yes
Did the SDT utilize the VRF Tool recently developed by the Process Subcommittee of the NERC SC to develop the VRFs? If not, the VRFs should be revisited using this tool.
No
In M3, it isn't clear what is meant by "including the criteria itself." The criteria is already specified in Requirement R3, so this phrase does not appear to be needed. M5 should only apply to PCs who would be part of a particular joint island. The present wording seems to suggest that M5 and Requirement R5 would apply to every PC. The wording for M5, and corresponding Requirement R5, should be modified to apply only to the PC's which would be involved with a particular island.
No
For Requirement R11, the 'Lower' VSL needs rewording. This VSL as written is just a repeat of the requirement text. Also, the time ranges for the VSL's should be expanded. Suggested ranges: Moderate: 12-14 months; High: 14-16 months; Severe: 16-18 months.
No
Requirement R1 should be revised to read "Each Planning Coordinator, in coordination with its constituent Transmission Owners and Transmission Planners, shall develop and document criteria…". Further, it should include that the Regionla Entity should be involved in the studies, as in many cases, the RE has performed or were involved in thses studies. similarly, Requirement R2 should be revised to read "Each Planning Coordinator, in coordination with its constituent Transmission Owners and Transmission Planners, shall identify one or more islands…". Requirement R3 should be revised to read "Each Planning Coordinator, in coordination with its constituent Transmission Owners, Distribution Provider and Transmission Planners, shall develop a UFLS program…" The Planning Coordinator should in all UFLS related activities include UFLS plans and procedures which their Transmission Owner, Distribution Provider and Transmission Planners may have had in place, and functioning adequately, perhaps for many years.
Yes
Yes
No

Because EOP-003-1 is the primary load shedding standard, and because UFLS has been removed from EOP-003-1 and placed in PRC-006-1, standard EOP-003-1 should note in the “Purpose” section that UFLS is addressed in PRC-006-1. The stated purpose of EOP-003-1 is to have the capability and authority to shed load rather than risk uncontrolled failure of the interconnection if there is insufficient generation or transmission capacity. It is not clear when and how it is determined that an "automatic" load shedding scheme is necessary or required. Are all TO’s required to have undervoltage load shedding plans in place? Suggest changing the ending phrase of R2 in EOP-003 from “required” to “necessary to minimize the risk of uncontrolled failure of the Interconnection.” Also suggest a review of other UVLS stanadrds for consistency with revised EOP-003.
Yes
No
While this is an improvement over the previous draft, we still believe that Requirement R3.3, dealing with generator V/Hz limitations, should not be part of this standard.
Yes
Yes
No
It is not clear what should be included in automatic switching. This requirement is vague. It appears that Requirement R9 would address anything that Requirement R10 would have been intended to cover.
No
The intention of R13 is good but a provision should be provided for each Planning Coordinator to comply with R11 in the event that it is not feasible to satisfy R13 within the one year assessment period. The Planning Coordinator’s compliance with R11 should not be dependent on actions by others. The 500 MW limitation discussed in the background section should be included in R11 to make sure this thought is not lost if/when the standard becomes effective. There is no need to evaluate smaller islanding events.
Yes
Group
SPP System Protection and Control Working Group
Shawn Jacobs
Southwest Power Pool
Yes
No
What is meant by “criteria” in Requirement R1? Does “criteria” in R1 have to be justified?
No
For R11, the lower VSL is stated as a requirement and not as a VSL. Does it need to be reworded?
Yes
Yes
Yes
Yes
No
Why are Generator Owners not included in the Standard? The Planning Coordinator can’t prove the design without the Generator Owner for Requirements R3 and R4.
Yes
Yes
Yes

Yes
Yes
Yes
Group
SERC Planning Standards Subcommittee
Philip R. Kleckley
South Carolina Electric & Gas Co.
Yes
No
M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that it be deleted. M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. Recommend that the wording in M5 be changed to: "Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified islands in accordance with Requirement R5 and identifies the affected Planning Coordinators." Recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint."
No
The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe 16-18 months.
Yes
Yes
No
Because EOP-003-1 is the primary load shedding standard, and because UFLS has been removed from EOP-003-1 to PRC-006-1, standard EOP-003-1 should note in the “Purpose” section that UFLS is addressed in PRC-006-1. Suggest changing the ending phrase of R2 in EOP-003 from “required” to “necessary to minimize the risk of uncontrolled failure of the Interconnection.”
Yes
Yes
Yes
Yes
No
It is not clear what is included in automatic switching. This requirement is so vague that it does not appear to add anything in addition to the UFLS program design that it is intended to address. It appears that anything that R10 may be designed to address is already covered by R9.
No
The intention of R13 is good but a provision should be provided for each Planning Coordinator to comply with R11 in the event that R13 is not satisfied within the one year assessment period specified in R11. A Planning Coordinator’s compliance with R11 should not be dependent on actions by other Planning Coordinators. The 500 MW limitation discussed in the background section should be included in R11. There is no need to evaluate smaller islanding events.
Yes
The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee only and should not be construed as

the position of SERC Reliability Corporation, its board or its officiers.
Individual
Michael R. Lombardi
Northeast Utilities
No
The VRF for Requirement R1 is stated as a Lower. The requirement to develop program criteria in Requirement R1 is as important as those requirements stated in Requirement R2 which is assigned a Medium VRF. Suggest the Requirement R1 VRF be revised to Medium.
Yes
Yes
Although NU agrees with the intent of the subject VSLs, we suggest that for Requirement R8 (Moderate and Severe) that the text beginning with OR is deleted. Additionally we suggest: • For Lower, Moderate and High VSLs - the first sentence be revised to read “The UFLS Entity provided data, in the format specified, to its Planning …” • For Severe VSL - the first sentence be revised to read “The UFLS Entity failed to provide data, in the format specified, to its Planning Coordinator(s) within 20 calendar days …”
Yes
Yes
Yes
EOP 003 is on the list of standards identified by the NERC Tiger Team for fast tracking of Order 693 directives. There is concern that coordination between these two DT’s may not have occurred and that the changes agreed upon in the revised UFLS SAR should also be considered by the Tiger Team.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Robert Ganley
Long Island Power Authority
No
The VRF for R1 for the development and documentation of UFLS program criteria is stated as a "Low" VRF. Such a requirement to develop overall UFLS program criteria was more than a "Low" or Admininstrative requirement and that the VRF for this requirement should be listed as Medium VRF. The requirement to develop a program criteria in Requirement R1 is as important as those requirements stated in Requirement R2 which was assigned a Medium VRF by the DT.
Yes
Yes
Yes
Yes
Yes

No
Yes
No
No
Yes
Yes
Yes
Yes
Individual
John Bussman
AECI
Yes
No
: For M1, how can we consider historical events if we have never had a UFLS event on our system? How would a system study tell us how to select an island? This is unclear.
No
In R1 it is unclear how to use historical events and system studies to select portions of the BES. In R4, I can see how we should be responsible for our own generators, but the information for generation owned by others is only as good as the data we receive. In R7 for the lower VSL, up to 40 days seems like it would include 30, should it be changed to say between 30 and 40? In R11, for the lower VSL, it appears to be just a restatement of the requirement rather than a VSL.
No
It is unclear what is meant by footprint if it is not a regional entity footprint. For those of us on a heavily interconnected border between two regional entities, do we now share a footprint with them? What about other utility's loads on our system, or vice versa, would we share a footprint with them as well? Also, R2.3 talks about if you are in multiple footprints, each of those footprints shall be identified as an island. Does that mean each footprint is a separate island or each footprint is included in the same big island?
No
R4 says voltage or power flow levels must be considered when designing an automatic load shedding scheme. Our UFLS scheme is an automatic load shedding scheme that does not take voltage or power flow levels into account. R4 needs to be reworded so that it is clear that it is ok to have automatic UFLS schemes that do not rely on under voltage or power flow levels.
No
It seems like generator owners should be added here, especially since R4 deals with generator frequency settings
No
It is unclear what the system frequency should be after the blue line ends.
No
AECI can understand how we should be responsible for our own data, but the data we use for others is only as good as the data we receive. It seems like this standard also needs to apply to generator owners
No
What if somebody else, with more stringent criteria than us, identifies us as an island and wants us to then conform to their more stringent criteria? It seems like if we did not identify them, the burden should not be placed on us. Also there seems to be potential for the actions of another utility to determine our compliance.
Yes

No
R13 seems unreasonable. If we do everything in our power to concur with another planning coordinator and they do not concur, our compliance is then determined by somebody else's actions.
Individual
Darryl Curtis
Oncor Electric Delivery
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
James A. Ziebarth
Y-W Electric Association, Inc.
Yes
Yes
No
Regarding the VSLs for R8, the UFLS entities cannot be punished for failing to meet a schedule if the schedule is not mutually agreed upon between the Planning Coordinator and the UFLS entities to ensure that the UFLS entities are capable of meeting such a schedule. At the very least, there must be some protection for the UFLS entities provided that requires the Planning Coordinator(s) to give the UFLS entities long-term notice of the deadlines that they will need to meet. The lack of any scheduling restrictions for the Planning Coordinators in the standard as written has a strong potential to cause enormous burdens on small UFLS entities that simply do not possess the resources to deal with such data reporting requirements without sufficient advance notice. Additionally, the UFLS entities cannot be penalized for failing to submit data in a format over which they have no control or input. The Planning Coordinator should be required to consult with the UFLS entities and decide upon a mutually agreeable data format in order to ensure that the UFLS entities are capable of providing the required data in the required format. With no language in the standard limiting or clarifying what data can be required of the UFLS entities by the Planning Coordinator, this provision at least should be made to protect small UFLS entities with highly limited resources for dealing with such data reporting requirements.

Yes
Yes
Yes
Yes
No
Because Load Serving Entities (not Distribution Providers) are actually responsible for the load in the current Functional Model and Compliance Registry Criteria, they should also be included in the applicability section of this standard.
Yes
Yes
Yes
No
Y-WEA is concerned about this requirement in that it seems to require the installation of facilities rather than just relays. 16 USC 824o (a)(3) gives NERC the authority to regulate existing facilities and planned additions or modifications to those facilities, not to prompt or require modifications or additions to the existing facilities. This proposed requirement seems to run afoul of this section of the USC.
Yes
Yes
Group
SERC SC UFLS Standard Drafting Team
Bob Jones, Chairman
Southern Company Services, Inc
Yes
No
M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that it be deleted. M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. Recommend that the wording in M5 be changed to: "Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified islands in accordance with Requirement R5 and identifies the affected Planning Coordinators." Recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint."
No
The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented." The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.).
No
R5 and R13 seem very problematic. The standard requires that both or all the entities agree. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two companies cannot agree. We

recommend that the following language be added to R5: “If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island.” We recommend that R13 be eliminated since it is covered by R11.
Yes
Yes
Yes
We recommend that R3 be revised to require the PC to specifically notify the “UFLS Entities” in their PC area that are part of the PC’s UFLS program.
Yes
Yes
No
see above comment to questions #2 and #4.
Yes
It is not clear what is included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching of a capacitor to avoid overvoltage). R10 refers to “Elements” and M10 refers to “Facilities.” In both R9 and R10, replace the word “provide” with “implement.”
No
As noted in our response to question #4 above, we recommend elimination of R13. The 500 MW limitation discussed in the background section should be included in R11. There is no need to evaluate smaller islanding events.
Yes
Group
NERC Staff
Mallory Huggins
NERC
Yes
NERC staff understands and supports this change to replace the groups with individual Planning Coordinators and agrees that it is a good hybrid approach. While NERC recognizes that the move might not be the ideal way to coordinate interregionally, at this point it does seem to be the best way to assign these requirements.
Yes
NERC staff agrees that it is wise to revise requirements specific to Underfrequency Load Shedding in EOP-003-1 to remove inconsistencies and redundancies. The only concern is that because both ad hoc team for expediting certain standards processes and the original EOP-003-1 SDT are working on modifications to the standard, there could be some overlap and miscommunication, especially with respect to these redundancies between PRC-006-1 and EOP-003-1.
Yes
NERC staff agrees that it is wise to revise requirements specific to Underfrequency Load Shedding in EOP-003-1 to remove inconsistencies and redundancies. The only concern is that because both the team of experts (formerly known as the Tiger Team) and the original EOP-003-1 SDT are working on modifications to the standard, there could be some overlap and miscommunication, especially with respect to these redundancies between PRC-006-1 and EOP-003-1.
Yes
NERC staff believes that the SDT has sufficiently identified the proper entities for UFLS coverage. NERC staff understands the comments raised by the industry regarding transfer of responsibilities, however, it is worth noting that some inconsistency has been created by the language used in the standard. It could be problematic that the entity with the original responsibility (the Distribution Provider) can delegate responsibility to another entity (the

Transmission Owner), because even with that delegation, the Distribution Provider's original responsibility does not disappear.
Yes
Yes, NERC staff supports the idea of better demonstrating coordination with the requirements proposed for PRC-024.
No
NERC staff disagrees with limiting the level of modeling in the assessments and feels that the modeling of generation should go beyond the 20 MVA and 75 MVA units as proposed. NERC staff believes that the UFLS design assessment should not be limited to modeling BES-connected resources. During a frequency excursion, all generation and frequency responsive devices "see" the excursion and react to it, regardless of size and location. Further, as penetration increases for similarly influential blocks of non-traditional resources (i.e., wind and solar farms) that have common underfrequency trip performance characteristics, it is essential that these dynamics and underfrequency trip characteristics should also be modeled and taken into account. This is not to say that each individual wind turbine or 500 kW generator must be modeled everywhere. However, when aggregate groupings of smaller units are known to be influential in dynamics analysis, or groupings of non-traditional resources with like frequency performance characteristics exist, it is essential that their influence be analyzed regardless of their voltage connection. The contribution to frequency response or common-mode tripping of such resources could mean the difference between a successful and unsuccessful UFLS system design.
Yes
Yes
Yes
Yes
Individual
Jonathan Appelbaum
United Illuminating Company
Yes
Yes
Yes
Yes
Yes
Yes
No
R1 should use term "shall implement manual load shedding". The Drafting team note says that PRC-006 is a Planning Standard and therefore EOP-003 R1 is needed to apply to the actual implementation of automatic load shed. We disagree that PRC-006 is solely Planning. The UFLS entity is required to implement the program, meaning protective devices are deployed and armed. By creating the program and arming the protection systems the UFLS Entity has committed to load shed. EOP-003 R1 is addressing the steps or actions a Transmission Operator takes to respond to insufficient resources. The Transmission Operator does not initiate automatic UFLS. The UFLS program is created by the Planning Coordinator and implemented by Transmission Owners and DP. EOP-003 requires the BA and TOP to perform load shed. Again, for UFLS this implies the TOP and BA have on/off control for UFLS protection systems. This we know is not true. The TOP/BA has the authority to implement manual load shed. A similar argument is made for R3. R3 should be "coordinate manual load shed plans". Coordinating plans is a Planning Horizon exercise. Therefore EOP-003 R3 coordination of ufls load shed by TOP/BA is a duplicate function to the PRC-006 coordination by Planning Coordinators. The entity with the best knowledge to coordinate UFLS is the Planning Coordinator. TOP and BA are coordinating the manual load shed plan with the recognition the UFLS is installed. In R5 add the words "automatic load shedding scheme other than UFLS". This will help compliance monitoring by explicitly differentiating this from PRC-006. Update the VSL also with this clarification.
Yes

Yes
Yes
Yes
Replace "reach" with "obtain".
Yes
Yes
Yes
Individual
Kasia Mihalchuk
Manitoba Hydro
No
The VRFs for R3, R4, R9, and R10 should be reduced from “High” to “Medium” for several reasons. System events that would activate automatic underfrequency load shedding have been very rare and automatic UFLS is a system preservation measure of last resort, not primary system preservation measure. For R4 in particular, the performance of the UFLS program and the associated islands do not change rapidly or dramatically to warrant a “High” VRF for delayed conducting or documentation of a UFLS design assessment.
No
Suggest that the measures be modified to reflect any changes made to standards Requirements per the comments made to questions Q4 through Q13. M10 – Replace “automatic switching of Facilities” with “automatic switching of Elements” to be consistent with the associated Requirement R10.
Yes
Yes
No
We propose that the scope of the SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and moving them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and moving them to a new PRC standard
No
In line with the comments for Question 6: R2 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard. R3 – add the qualification “coordinate manual load shedding plans”. R4 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard. R5 – add the qualification “implement manual load shedding plans”. R7 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.
Yes
No
1. In R3, the term, “imbalance”, should be described using the standard industry nomenclature of imbalance = (load-generation)/generation. The present definition defines imbalance as being the same as the required percent load to be shed, and if this is what is intended, it would be better to keep it simple say that everyone needs to shed at least 25% load and avoid use of the term imbalance. In any event, the definition of “imbalance” should follow industry conventions for consistency. For R4.1, R4.2, R4.3 - Attachment 1 and 2: 2. The titles for Attachment 1 and 2 should clearly qualify that the transient frequency performance curve applies for a 25% or less island imbalance and that programs which are larger than this minimum load shedding requirement do not have to meet this criteria when overloads are in excess of 25%. [If the SDT doesn’t allow different characteristics for a higher than 25% program, then we propose that the MRO submit a variance for a 30% and higher UFLS programs.] We are quite concerned that the generation tripping curve part of attachments 1 and 2, which matches the curve in PRC-024, as it appears to that this applies to all overload levels and to any size of load shedding program. It can be easily demonstrated that as the size of the load shedding program is increased, that

generation protection settings have to be modified accordingly. The reason is to achieve coordination objectives. When we are dealing with the larger imbalances we are also inherently dealing with lower minimum frequencies and longer frequency recovery times. To make matters worse, we are trying to approve PRC-006 using information from PRC-024 which is still a draft, not an approved standard. We would like to elaborate on problems related to the generation protection curve part of attachment 1: UFLS programs have to deal with several mutually conflicting objectives and by setting hard and fast limits for generation underfrequency protection up front, we are adding an unnecessary constraint which will have undesirable effects on other aspects of the program. Such generation protection settings have to be considered in the context of the overall set of compromises that go into UFLS program design. We have to consider what kind of frequency recovery can be achieved with a well coordinated load shedding program and we have to compare that performance to the true capabilities of the generation in the island. When all things are considered, a final compromise can be reached that gives the best of all worlds. The characteristic in PRC-024 is not representative of the raw data from the manufacturers that defines actual capabilities, instead it is just someone's estimation of what is a reasonable tradeoff, and represents some hypothetical amount of accelerated loss of life of the turbine. The generation protection curve from PRC-024 is at best a starting point. From a design perspective, we could use different and equally valid settings if needed. 3. The Under Frequency Performance Characteristic line in Attachment 1 should be extended from the knee at approximately 58.9 Hz (for 60 seconds) to 59.3 Hz or 59.6 Hz (at for approximately 500 sec). The purpose is to define a single line of constant slope and to get rid of the arbitrary knee in the characteristic which serves no reliability purpose. The reason for this change is that the worst case frequency recovery time for frequencies between 58.7 Hz and 59.5 Hz may occur for imbalance conditions significantly less than 25% where the governor response prevents the load shedding blocks from picking up and where frequency recovery times is are a function of governor response and system inertia. Likewise it makes sense to extend this line below 58 Hz to at least as low of a frequency as is covered by the generation protection curve spicily for the hydro generator as of Manitoba Hydro case. 4. Add a note to Attachment 1 that states, "Larger size UFLS programs (e.g., 60%) may require less restrictive (lower) underfrequency (as well as and/or longer time delays) due to island generation and protection characteristics. UFLS programs shedding more than 25% must also increase generation protection delay times and/or change set points to achieve coordination with load shedding. For example, Manitoba Hydro needs to shed more than 30% of the area load to achieve reasonable frequency recovery in it island. In this case, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable. For R4.4, R4.5, R4.6 - Attachment 2: Generator Underfrequency and Overfrequency Attachments: 5. The Generation Owner off-nominal frequency coordination requirements and coordination curves should be included in the PRC-006 standard and PRC-024 should be scrapped. How can PRC-006 even proceed with using curves from PRC-024 when PRC-024 is still being drafted and subject to change? We could approve PRC-006 only to find subsequent changes to PRC-024 have undermined everything. The generation curves which are used to set generation underfrequency protection need to be appropriate for the system studied and one size does not fit all. The generation protection curves in Attachments 1 and 2 appear to be someone's personal estimation of what is a reasonable amount of accelerated loss of life per event but the flaw is that this was developed without first finding out what is really needed to ensure a well coordinated UFLS plan that meets all of the other objectives (planning engineers need to be able to coordinate generation protection with load shedding frequency recovery times as part of the study process, as the recovery times are influenced by the design objectives of the UFLS program). This generation off-nominal frequency characteristic is not what manufacturers provide as limits on their machines. No technical justification was ever provided for these curves that were developed in PRC-024, and that justification is needed. It is insufficient to say that PRC-006 is justified in using this just because it came from PRC-024. The technical justification was never part of any NERC standards drafting effort. Limits of this nature should not be created arbitrarily, and have to be selected as part of the overall final compromise involved in UFLS design to ensure we give enough time for load shedding to operate under worst case conditions, and as much time as possible needs to be given for frequencies close to 60 Hz as UFLS events show that in the real world that things do not always work as planned and system frequency can stall out below 59.5 hz for a long time while operators try to deal with this by manually shedding load. If the generation protection curves are not appropriate for programs covering overloads beyond 25%, then the titles of the curves should qualify that they apply for a 0% to 25% imbalance and include an note that different settings may be needed to coordinate with UFLS programs that shed more than 25% of the island load. Volts/Hertz Performance Characteristic: 6. The Volts/hertz requirement is not need in this standard. There are a couple of reasons. Voltage regulators automatically reduce voltage according to volts per hertz when in the automatic mode so they self protect. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist that adequately address the volts/Hz issue. If voltage regulators are in automatic, the 110% volts/Hz limit kicks in between 57.2 Hz and 61.8 Hz assuming the voltage regulator holds terminal voltage within the allowed 1.05 pu to .95 pu range. Units with voltage regulators in manual will just trip when volts

per Hertz protection picks up. Units are normally in automatic control so this is not a big worry. It appears this requirement is appropriate for programs which may experience frequencies below 57.2 Hz, but few programs will see frequencies this low. Of course that makes it very easy to demonstrate that programs satisfy this requirement, but it still seems there is no need to put this in the standard. As such, we believe the Volts/Hz requirement is of questionable worth for programs covering overloads of up to 25%, and should be removed. Even if system frequency were to drop below 57.2 hz, this performance characteristic cannot presently be properly simulated in stability cases as the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation.

Yes

No

Replace the words “reach concurrence with” with “provide UFLS design assessment results to”. Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words “other affected Planning Coordinators” with “other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of “other affected Planning Coordinators” is too vague and could be interpreted and categorized differently by various entities and auditors.

Yes

No

1. For R11, replace “Each Planning Coordinator, in whose footprint . . . to evaluate” with “When a disturbance event occurs in a Planning Coordinator’s footprint that involves automatic UFLS program operation or frequency excursions should have activated UFLS program operation, and a final disturbance report is required per EOP-004, each Planning Coordinator shall evaluate within one year of the disturbance event:”. 2. We have concerns about specifying that the evaluation must be complete within one year we know that some historical studies of events that included UFLS took longer than one year [e.g., three years] to complete. Therefore, we would prefer a more flexible wording, a longer time frame to be used in this requirement. Perhaps the requirement could stipulate that the evaluation must begin within 6 months and be completed within the schedule set by the investigative team. 3. For R13, replace “in whose footprint . . .on the event assessment result” with “that conducts an UFLS design assessment (per R12) for islands where other Planning Coordinators have design assessment responsibilities shall provide a design assessment report to those Planning Coordinators.” The reference to the event assessment report should be part of R11. The qualification of “event affecting multiple Planning Coordinators” is too vague and could be interpreted and categorized differently by various entities and auditors.

Yes

We are contemplating a variance. However, this variance must apply to other areas such as Manitoba Interconnection within MRO to address the physical characteristics of the Manitoba system. Manitoba system physical characteristics are very much similar to Québec system. More than 90 % of installed generation in the Manitoba Interconnection is hydraulic. Manitoba Hydro may provide modifications to attachments 1B and 2B that would be applicable for Manitoba hydro area and cover UFLS program for an imbalance of more than 25%.

Individual

Edward Davis

Entergy Services

Yes

We recommend that the VRF Tool be used to validate the proposed VRFs.

No

M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that the phrase be deleted. M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. Recommend that the wording in M5 be changed to: "Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified islands in accordance with Requirement R5 and identifies the affected Planning Coordinators." Recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint."

No

The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented." The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.).
No
R5 and R13 seem very problematic. The standard requires that both or all the entities agree. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two companies cannot agree. We recommend that the following language be added to R5: “If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island.” We recommend that R13 be eliminated since it is covered by R11.
Yes
Yes
No
1. We recommend that R3 be revised to require the PC to specifically notify the “UFLS Entities” in their PC area that are part of the PC’s UFLS program of the UFLS program. 2. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information.
Yes
Yes
No
See above comment to questions #2 and #4.
Yes
It is not clear what is included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching of a capacitor to avoid overvoltage). R10 refers to “Elements” and M10 refers to “Facilities.”, please change one of the references for consistency. In both R9 and R10, replace the word “provide” with “implement.”
No
As noted in our response to question #4 above, we recommend elimination of R13. The 500 MW limitation discussed in the background section should be included in R11. There is no need to evaluate smaller islanding events.
Yes
Group
Bonneville Power Administration
Denise Koehn
BPA, Transmission Reliability Program
Yes
No
Measures are too vague, lacking specifics, and not performance-based. This would leave too much up to the Auditor’s interpretation. Measures are only valuable if they contain specific targets or specifications that clarify how an entity will be deemed to be compliant with the standard as written. Measures which merely repeat the standard with the inclusion of “shall have evidence such as…” are not very useful. Measures should be explicit, detailed, consistent, and provide useful guidance to entities. These measures do not provide any useful guidance beyond

what is specified in the requirement itself.
No
Criteria are never actually defined in the requirements. Planning Coordinator footprints are not established. What does “annually maintain” mean? Does it mean the Database requires annual updates, annual reviews or just to provide a database annually? Frequency excursions precede an islanding event. I.e. low frequency initiates UFLS which should prevent an unintentional islanding event. The wording of this requirement makes it seem like the islanding event occurs first and causes the UF.
No
It doesn’t make sense to assign responsibilities to organizations that are not currently formed. Footprint or jurisdiction of Planning Coordinators has not been established and no mechanism exists for assigning a specific UFLS entity into a PC’s jurisdiction. PCs within an interconnection should be required to develop an Interconnection Coordinated UFLS Plan. UFLS works on interconnection basis not on PC footprint basis. The purpose of the UFLS Plan is to mitigate the need to form islands by balancing loads and resources; a secondary function would be to balance the loads and resources after the islands have been formed. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts within the interconnection.
Yes
No
EOP-003-1 and the current version of EOP-003-2 still include automatic UFLS. EOP-003-2 should include reference to manual load shed only. To include UFLS that is undefined would cause a conflict with PRC-006.
No
LSE should also be included as a “possible” UFLS entity some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. In addition to the issue previously stated concerning PC authority, no valid way exists to determine which registered entities are under the jurisdiction and authority of any Planning Coordinator. The current version does not address customer-owned UFLS relays. There should be recognized sub-area group(s), which consists of PCs, as assigned by the Regional Assurer (RA) which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off-Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate nor address the interconnection reliability needs.
No
Each interconnection should establish discrete set points based upon stability and dynamic analysis. Discrete set points can help establish criteria which are measurable and performance-based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC. The Standard needs to be very explicit that the curves are interconnection performance curves and not entity specific set points. What is the technical justification and correlation of the curves to the UFLS Plans, i.e. where did these curves come from?
No
Underfrequency is an issue of load to generation balance regardless of the voltage of the interconnection.
No
If each Planning Coordinator may choose its islands, what then is the process for getting “Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by any one Planning Coordinator”. Who is the final authority and how is the arrangement memorialized and notified? No clear definition of a Planning Coordinator footprint may impact adequate identification of and authority related to establishing concurrence.
No
Requirement R10 is unclear and needs to be rewritten to clearly address the applicability.
No
Requirement R13 needs to rewritten because language is unclear, i.e. what is meant by “of UFLS actuated loss of load”?
No
The standard and performance requirements should reflect the individual interconnections and not a continent-wide standard. This would allow for the uniqueness of each interconnection to be

addressed similar to Hydro Quebec's variance. Other Comments: While the concern for loss of additional generation units because of their V/Hz protection schemes is understood, the bases for the 1.18pu and 1.1pu values are not evident and may not be technically supportable when compared against actual protection settings or allowable post-contingency voltage bands. Further, V/Hz protection settings vary across the system and it is unlikely adherence to this requirement will impact reliability. It will only increase dynamic analysis requirements. We recommend removing R3.3.
Group
Western Electricity Coordinating Council
Steve Rueckert
WECC
No
We agree that the proposed VRFs are appropriate for the subject of the requirements, but we do not agree with many of the requirements as drafted, so we are opposed for that reason
No
R1 unclear definition of "criteria" it is never actually defined in the requirement. R2 For clarity Severe level should use the term "greater than 2" of the parts instead of "all" of the parts R3 For clarity Severe level should use the term "greater than 2" of the parts instead of "all" of the parts R4 no comment OK R5 very difficult to apply since Planning Coordinator footprints are not established. VSL could be based on number of adjacent PC's that do not concur. R6 Not clear on what "annually maintain" means. Does it mean the Database requires annual updates, annual reviews or just the ability to provide a database annually? R7 at least some of the severity level should be based on the number of requests that were late rather than the time the request was overdue particularly since only an "annual maintenance" is required there is no difference in reliability impact if delivery is made in 30 or 60 days. R8 at least some severity level should be dependent on the lack of sufficiency of data as opposed to the amount of time it was overdue. R9 No comments I will assume the percentages have some basis and are not just arbitrary. R10 No comments I will assume the percentages have some basis and are not just arbitrary. R11 With respect to the VSLs I would recommend not combining the time duration and inclusion of parts. Use timing for lower and moderate and the lack of components for High and Severe. I have to be dumb here with the wording of the requirement. Does not the frequency excursion precede the islanding event. i.e. low frequency initiates UFLS which should prevent an unintentional islanding event. The wording of this requirement makes it seem like the islanding event occurs first and causes the UF This Requirement and VSL places emphasis on performing analysis and does not address any possible violation for actually having an inadequate UFLS program resulting in unintended islanding. R12 VSL should be binary. Severe for failure to perform the assessment in the required time. Actually the Requirement should be to "implement" the changes and correct the deficiencies not just to "consider" them in another assessment. If implementation were the focus the VSL's could be based on amount of implementation completed within a specified time frame. R13 See comments for R5 with respect to PC footprint and also there is no clear indication of what is meant by event affecting other PC's does this mean islanding in the other areas or UF load shed or equipment switching?
No
The PCs within an interconnection should be required to coordinate a UFLS Design with all other PCs within the Interconnection and the PCs should be required to develop an Interconnection Coordinated UFLS Plan. UFLS works on interconnection basis not on PC footprint basis. The primary purpose of the UFLS Plan is designed to mitigate the need to form islands by balancing loads and resources. It is a secondary function to balance the loads and resources after the islands have been formed. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts within the interconnection. From an audit and enforcement standpoint, no mechanism exists for assigning a specific UFLS entity into a PC's jurisdiction. This has the potential for making this standard unauditable for any entity which is not designated by a PC unless some guidance is established to determine a PC's footprint.
Yes
This really doesn't look like a question, and it appears the actual question is asked in number 6.
Yes
Agree with the removal of the words underfrequency and Balancing Authority in EOP-003, but do not agree with the EOP-003-1 or the current version of EOP-003-2 that is out for vote because it still includes automatic UFLS. EOP-003-2 should include reference to manual load shed only. It includes UFLS that is undefined and could cause a conflict with PRC-006.
No
LSE should also be included as a "possible" UFLS entity Some large interruptible customers

outside of DP or TO could be allowed to own UFLS devices. There should be a recognized sub-area group(s), which consist of PCs, as assigned by the Regional Assurer (RA) which is the agent(s) for overall coordination within the interconnection or sub-area. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate nor address the interconnection reliability needs.
No
The devices which implement UFLS must have discrete setpoints. The standards must establish criteria which is measurable. This type of criteria is only measurable by study or actual performance following a UFLS event. The planning criteria may use curves but these must be translated to a setpoint which can be verified. Each interconnection should establish discrete set points based upon stability and dynamic analysis. From discrete set points one can establish criteria which are measurable and performance based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC. The Standard needs to be very explicit that the curves are interconnection performance curves and not entity specific set points. What is the technical justification and correlation of the curves to the UFLS Plans, i.e. where did these curves come from?
No
Underfrequency is an issue of load to generation balance. It does not seem to make sense to make the distinction of whether or not a generator or generating facilities directly connect to the BES. The loss of 100MW of generation has the same impact on frequency if they are connected at 69kv or 500kv. The thresholds used in the standards are registration thresholds for the GO/GOP function and do not negate the impact of all generation on frequency response.
No
From an enforcement standpoint there is concern that if Planning Coordinator may choose its islands, what then is the process for getting “Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by any one Planning Coordinator”. Who is the final authority and how is the arrangement memorialized and notified? Also, please see comment to Question #8 concerning the role of the RA.
Requirement R10 is unclear and needs to be rewritten to assure the applicability.
From and enforcement standpoint whom is the final authority and how are arrangements memorialized and notified? In addition these requirements address issues which indicate a failure or inadequacy of the initial required planning process and appear overall to allow PC to establish a program based on inadequate study and then fix it after an event which proves the program was inadequate. All without any violation of standard.
The standard and performance requirements should reflect the individual interconnections and not a continent wide standard allowing for the uniqueness of each interconnection to be addressed similar to Hydro Quebec’s variance. There is not a place to provide a response to question 15 from the unofficial word verison, so it is being provided here. Q 15 While the concern for loss of additional generation units because of their V/Hz protection schemes is understood, the bases for the 1.18pu and 1.1pu values are not evident and may not be technically supportable when compared against actual protection settings or allowable post-contingency voltage bands. Further, V/Hz protection settings vary across the system and it is unlikely adherence to this requirement will impact reliability. It will only increase dynamic analysis requirements. We recommend removing R3.3.
Individual
Bob Thomas
Illinois Municipal Electric Agency
Yes
For R8, R9, R10 applicable to UFLS entity/TO.
Yes
For M8, M9, and M10 applicable to UFLS entity/TO.
Yes
Yes
Tbe SDT's consideration of comments during the second posting is very much appreciated. Applicability now reoognizes and preserves the widely used practice of a TO factoring interconnected DP (that does not own or operate UFLS equipment) load into the TO UFLS scheme.

Yes
Individual
Jon Kapitz
Xcel Energy
No comments
No comments
No comments
No
The problem still exits that the mapping of Planning Coordinators to 'subordinate' entities is not clear. Creating additional requirements for a functional entity that is still nebulous creates more confusion. We also believe the term "island" should be a defined NERC term. It is used throughout the standard with the meaning being generally understood within the industry but not explicitly stated.
No comments
No comments
No comments
No
We question why Generator Owners are not included as a UFLS entity. Under R4 PCs are required to obtain setting from them. We are not aware of another standard that requires GOs to provide those settings to the PC. Thus there should also be a requirement indicating that GOs (or UFLS Entities) provide data requested by the PC to conduct the required assessments.
No comments
No
We feel that our comment in the previous draft was not fully addressed. The dynamic simulation would need to include any small generators (<20MVA or <75MVA aggregate) that are not required to register, but together, could have a material impact on the BES. Additionally, it would need to be clear who is responsible for ensuring those material impacts are included in models/simulations. Distributed Generation (DG) is a growing concern that can have an impact on UFLS programs. Consider the need for adding that the assumptions related to DG be included in the R3 & R4 requirements Additionally, the Statement of Compliance Registry lists additional criteria for generator registration (i.e. black start, determined to be material to BPS). Shouldn't these be captured, or a more simple approach may be that all registered GOs be required to provide the requested data?
Yes
As long as the requirement as written still permits PCs to coordinate and select one or more islands between them to consider we are ok. Please clarify that R1 does not require that each PC must come up with their own unique island to consider.
No
We have concerns that R9 & R10 provide the Authority of a PC to direct investment and actions to another entity, without the agreement from that entity. Thus we feel that R5 should be modified to require concurrence from each affected UFLS Entity as well.
No
We don't believe these should be limited to islanding events. Suggest rewording to indicate that "events resulting in frequency excursions below initializing set points of the UFLS program, or actuate automatic switching or tripping shall …"
No comments
Individual
Jeff Nelson
Springfield Utility Board
Yes
Yes
Yes
Yes

There remains some abiguity with regards to the following language: "UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers" SUB is fine with the Planning Coordinator having the authority to determine UFLS requirements and affected entities. But there is a problem with regards implementation of a Planning Coordinator decides that equipment is required where it was not previously required by an entity. What is the process for the Planning Coordinator to provide notice to a registered entity (such as a Distribution Provider)? If a UFLS is required of a DP where a UFLS did not previously exist, what is the implementation plan for becoming compliant without having to be out of compliance on Day 1 just becuase a PC sent a letter? Under the implementation plan where it states: "The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time to develop or modify UFLS programs and to establish a schedule for implementation." Is this language intended for the PC to establish a schedule for implimentation of affected entities that fall under the standard after the standard is adopted?
Yes
Group
Tennessee Valley Authority (TVA)
Dennis Chastain
Power System Operations
No
TVA believes the following VRF changes should be considered: R4 - change from High to Medium. Justification: The selection of a 5-year interval for assessments seems subjective in nature. Failure to perform an assessment within a 5-year interval would not directly cause or contribute to bulk electric system instability. R11 - change from Medium to Low. Justification: documenting a post event assessment seems more administrative in nature, relative to R12.
No
TVA believes the following changes to the Measures should be considered: M3: It is unclear what action is intended by the phrase “including the criteria itself.” Since the criteria are specified in R3, it is recommended that it be deleted.
No
The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. Recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented." The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.).
Yes
Yes
Yes
TVA supports this direction to remove the automatic load shedding components (UFLS and UVLS) from EOP-003 to avoid potential conflict with the PRC standards that address UFLS and UVLS.
No
TVA supports the modifications to the EOP-003 standard which remove UFLS. We believe that EOP-003 should continue to be revised under the appropriate project to focus the emphasis on load shedding plans that are controlled by operator action, and exclude automatic protection schemes (UFLS and UVLS) that do not require operator action to execute their designed function. We have the following comments on the proposed modifications: R2 - We recommend that the text added at the end of this requirement be removed (“if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage

load shedding scheme is required."). This addition introduces entities that are not identified in the "Applicability" section of the standard (A.4). While simulations performed in the planning environment (TPL standards) would likely lead to this determination, references to the Transmission Planner and Planning Coordinator in this requirement will introduce compliance confusion. Can the SDT point to another standard that requires the Transmission Planner or Planning Coordinator to determine if an under-voltage load shedding scheme is required? Our preference would be to strike requirement R2 from the EOP-003 standard altogether, but we realize the scope of this project is limited to UFLS. R4 - With the deletions that are being proposed, we recommend that "undervoltage" be inserted into the requirement for clarification -- "automatic undervoltage load shedding scheme". R7 - Since the Balancing Authority has been removed, suggest changing "their areas" to "their area" (singular).
No
Our preference is that the applicability section of the standard remain "clean" with regard to the applicable entities listed, and not cluttered with qualifiers. For instance, we see no benefit in listing Transmission Owners twice (4.2.1 and 4.3). If this format is retained, we suggest that section 4 be revised to add clarity. We suggest that section 4.2 be revised to read: "UFLS entities shall mean all entities that are responsible for the ownership, design, or installation of UFLS equipment or automatic switching of Elements as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers" and that 4.3 be deleted. The terms "operation" and "control" are typically used in the context of an operating entity task (RC, TOP, GOP, BA). Therefore we prefer the use of "ownership, design, and installation" over "ownership, operation, or control". The omission of the Generator Owner from this standard is potentially problematic in that coordination with generator under- / over-frequency settings is needed. We also note that PRC-008-0 contains the phrase "required by its Regional Reliability Organization to have a UFLS program". Should this be changed to "required by its Planning Coordinator to have a UFLS program" to align with the proposed changes to PRC-006-1? Lastly, with the modifications to EOP-003, there is no linkage of operating entity applicability to UFLS. While beyond the scope of this drafting team's objectives, we believe that operator awareness of UFLS installations is a critical component of load restoration following an event that initiates UFLS tripping.
Yes
Yes
No
R5 (and M5) is problematic in that it requires all affected PCs to reach concurrence. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard should require that one PC change its methods because another PC(s) does not agree with its methods, or agree that another method is acceptable that it finds a problem with. There needs to be a process in the event that PCs cannot reach concurrence. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island."
No
It is not clear what is included in automatic switching. If it is the automatic switching of Elements for the sake of removing load, it would appear to be covered under R9. R10 refers to "Elements" and M10 refers to "Facilities". In both R9 and R10, suggest replacing the word "provide" with "implement".
No
TVA agrees with the intent of transitioning post-event analysis from PRC-009-0 to the proposed PRC-006-1 standard, but has the following comments: R11: The "500 MW or greater" threshold included in the background information should be included in R11. R13/M13: TVA has similar concerns with the requirement to reach concurrence with other affected PCs that are expressed in response to Question 11 for R5/M5. We recommend elimination of R13/M13, or the addition of language that would eliminate the compliance of a PC having dependency on the concurrence of one or more other PCs.
Yes
Individual
Charles Lawrence
American Transmission Co.
No
he VRFs for R3, R4, R9, and R10 should be reduced from "High" to "Medium" for several

reasons. System events that would activate automatic underfrequency load shedding have been very rare and automatic UFLS is a system preservation measure of last resort, not primary system preservation measure. For R4 in particular, the performance of the UFLS program and the associated islands do not change rapidly or dramatically to warrant a “High” VRF for delayed conducting or documentation of a UFLS design assessment.
No
M5 - As noted in the comments below for R5, replace the words “reached concurrence with” with “provided a UFLS design assessment report to”. Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words “other affected Planning Coordinators” with “other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of “other affected Planning Coordinators” is too vague and could be interpreted and categorized differently by various entities and auditors. M7 – As noted in the comments below for R7, replace “within their Interconnection”, with “that have design assessment responsibilities within the islands covered by the UFLS database”. Planning Coordinators that are within the same Interconnection, but are not within any islands covered by another Planning Coordinators UFLS database, would not need to receive the UFLS information. M10 – Replace “automatic switching of Facilities” with “automatic switching of Elements” to be consistent with the associated Requirement R10.
Yes
Yes
Yes
No
We propose that the scope of the SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for also removing the automatic UVLS requirements from EOP-003-1 and referring them to a new PRC standard.
No
In line with the comments for Question 6: R2 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and new PRC standard. R3 – add the qualification “coordinate manual load shedding plans”. R4 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard. R5 – add the qualification “implement manual load shedding plans”. R7 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.
Yes
No
1. In R3, the term, “imbalance”, should be described using the standard industry nomenclature of imbalance = (load-generation)/generation. 2. In R4, we interpret that the Equivalent Inertia Analysis is a valid dynamic simulation methodology for certain aspects of UFLS assessments. So, we expect that this type of dynamic analysis would be accepted toward compliance with the “through dynamic simulation” portion of this requirement Attachement 1 for R4.1, R4.2, R4.3 3. The title for Attachment 1 should clearly qualify that this curve applies for a 25% or less island imbalance. The curves that should be used for UFLS programs associated with imbalance levels greater than 25% (e.g. 30%, 40%, 50%) would be different from the 25% curve. 4. The Under Frequency Performance Characteristic line in Attachment 1 should be extended to 59.5 Hz (at 500 sec). The reason for this change is that the worst case response between 58.7 Hz and 59.5 Hz may occur for imbalance conditions significantly less than 25% where the governor response prevents the load shedding blocks from picking up and where response recovery times is a function of governor response and system inertia (30 seconds to 500 seconds). This removes the knee of the curve at 30 seconds and extends the curve up to 500 seconds. This would change the 30 second at 58.9 Hz cut off point to 500 seconds. 5. Add a note to Attachment 1 that states, "Larger size UFLS programs (e.g., 40%) may require less restrictive (lower and/or longer time delays) underfrequeny limits due to island generation and protection characteristics." UFLS programs shedding more than 25% must increase generation protection delay times and/or change set points to achieve coordination with load shedding. For example, Manitoba Hydro and Saskatchewan need to shed more than 30% of the area load to achieve reasonable frequency recovery in their islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable. Attachment 2 for R4.4, R4.5, R4.6 6. The title for Attachment 2 should clearly qualify that this curve applies for a 25% or less island imbalance. The curves that should be used for UFLS programs associated with imbalance levels greater than 25% (e.g. 30%, 40%, 50%) would be different from the 25% curve. Generator

Underfrequency and Overfrequency Attachments 7. The Generation Owner off-nominal frequency coordination requirements and coordination curves should be included in the PRC-006 standard. The generation curves should be applicable for load shedding levels beyond the 25% (e.g. 30%, 40%, 50%). If curves beyond 25% are not include, then the titles of the curves should qualify that they apply for 25% imbalance and include an note regarding coordination with UFLS programs that shed higher than 25% of the island load. The line should extend to 57 Hz (at .3 sec) to 59.5Hz (at 1800 sec). The minimum frequency of 57.0 Hz was chosen because most conventional generation can briefly operate down to 57.0 Hz and large load shedding programs may need to make use of that capability to achieve coordination with these UFLS programs. Volts/Hertz Performance Characteristic 8. The Volts/Hz requirement should be removed. This performance characteristic cannot presently be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation. In addition, the Volts/hertz requirement is not need in this standard. Voltage regulators automatically reduce voltage according to volts per hertz when in the automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist that adequately address the volts/Hz issue.
Yes
No
Replace the words “reach concurrence with” with “provide UFLS design assessment results to”. Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words “other affected Planning Coordinators” with “other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of “other affected Planning Coordinators” is too vague and could be interpreted and categorized differently by various entities and auditors.
No
Consideration should be given to replacing “Transmission Owner” with “UFLS Entity” because the automatic switching of distribution Elements (e.g. capacitor banks) may be more effective and practical UFLS design than restricting the scope of the requirement to just transmission Elements.
No
1. For R11, replace “Each Planning Coordinator, in whose footprint . . . to evaluate” with “When a disturbance event occurs in a Planning Coordinator’s footprint that involves automatic UFLS program operation or frequency excursions should have activated UFLS program operation, and a final disturbance report is required per EOP-004, each Planning Coordinator shall evaluate within one year of the disturbance event:”. 2. Either part of or after R11, there should be a requirement that “Each Planning Coordinator shall provide a preliminary event assessment report to the other Planning Coordinators who must conduct an assessment of the event for review at least 90 days before finalizing the event assessment report. 3. For R13, replace “in whose footprint . . .on the event assessment result” with “that conducts an UFLS design assessment (per R12) for islands where other Planning Coordinators have design assessment responsibilities shall provide a preliminary design assessment report to those Planning Coordinators for review at least 90 days before finalizing the design assessment report. The reference to the event assessment report should be part of R11. The qualification of “event affecting multiple Planning Coordinators” is too vague and could be interpreted and categorized differently by various entities and auditors
Yes
Group
Western Area Power Administration
Brandy A. Dunn
Western Area Power Administration - Corp Services Office
No
R2 thru R5 - is specific to under voltage conditions but the "Purpose" of the standard states is for insufficient generation along with insufficient xmsn capacity. Also the Transmission Operator does not establish plans or coordinate for auto load shedding for under voltage conditions - this is a

function of Planning R6 and R7 - now the requirements are back to under frequency along with under voltage. R8 - states the Operator shall be capable of implementing load shed adequate for responding to the EM - in most cases there is not enough time to respond manually. Is this referencing if a condition develops slowly enough to have time to respond? Seems like the purpose and requirements should be further defined so that EOP-003 is specifically for BA and Transmission Operations for developing low voltage/frequency conditions with ability/authority to shed load and PRC-006 for Planning defining auto load shed for low voltage/frequency conditions.
No
Individual
Scott Berry
Indiana Municipal Power Agency
Yes
Yes
Yes
Yes
Yes
IMPA agrees with these actions.
Yes
Yes
However, changes need to be coordinated with the tiger team and their changes to EOP-003-1.
Yes
IMPA believes that this draft allows entities who are currently providing UFLS at the transmission level to stay in place and provide this service going forward. IMPA hopes that the Planning Coordinators will establish their UFLS program by using this current UFLS setup prvided by Transmission Owners and not force a financial burden onto Distribution Providers by requiring then to install UFLS equipment. In states such as Indiana and Illinois, UFLS is performed at the transmission level for some entities and includes all the distribution load in the area regardless of size and voltage connection to the BES.
Yes
Yes
When looking at generation in the RFC region and by going with generating units that are specified in the current sub requirements of requirement 4, the Planning Coordinators will be capturing 96 PERCENT of the generation in the RFC region in their UFLS program and design assessment (data supplied by RFC). When looking at generation between 69kV and 100kV, only about 2 PERCENT increase is gained in this area by requiring these Generation Owners to report information (this is making the assumption that all these lower voltage units have UFLS relays). One has to question the value of this increase in requiring these generating units to report information when load is not being captured that accurately and the modeling has a certain percent error. In addition, NERC reporting requirements will have to apply to these generating units connected between 69kV and 100 kV which will force the NERC registration of these units. NERC compliance has made the statement on several documented occasions that if a new Generator Owner goes on the NERC registry, then that entity will have to meet ALL the NERC Generator Owner standard requirements in a NERC and FERC audit, NOT just the NERC UFLS standard. This would be a case where a standard drives the NERC Registry and IMPA does not believe that reliability standards should drive and change the NERC Registry.
Yes
Yes

Yes
Yes
Individual
Claudiu Cadar
GDS Associates
No
- Standard not entirely clear regarding to whom will apply (see 4.), groups or individual Planning Coordinators within the Regional Entity footprint. - Not sure what is the intent for paragraph 4.3
No
- See the answer to question 10. pertaining the classification of generating units / plants
No
- Not sure what is the intent of this classification of generating units >20MVA, generating facilities (two or more units) directly connected to BES >75MVA and generating facilities connected to a common bus to BES >75MVA - Are the requirements for the two categories of facilities larger than 75MVA meant to overcome the differences regarding the point of interconnection? If affirmative 3.3.3, should state “Generating plants / facilities greater than 75MVA (gross aggregate nameplate rating) connected to the BES at a common point of interconnection (sharing a common station bus)”
No
- Requirement R1 is quite unclear. Not sure how the criteria will be developed especially to include the interconnected adjacent sections of the BES. What if one of the adjacent entities does not agree to the criteria? Is that OK because the Planning Coordinator will no longer join groups so is no need to coordinate?
No
- Requirement R11. The one year deadline it seem very long. There can be multiple events before assessment is due. - Requirement R12. Same comment regarding the assessment due date.
Individual
Joe Springhetti
Wisconsin Electric Power Company (dba We Energies)
Yes
Yes
We agree with the Measures as far as the draft standard is currently written, however, see our comments for questions 11, 12, and 13 that would require modifications to requirements R9 & R10 and to M9 & M10.
Yes
We agree with the Violation Severity Levels as far as the draft standard is currently written, however, see our comments for questions 11, 12, and 13 that would require modifications to requirements R9 & R10 and the corresponding Violation Severity Levels.
No
Although we agree that the Planning Coordinator has the wide-area view and technical skills to oversee the design of and ensure the effectiveness of a UFLS program, we are concerned with how this concept will actually play out, especially when a UFLS Entity is within multiple Planning Coordinators’ footprints.
Yes
See comments for question 6 and 7.
Yes

We agree with the expanded scope of the supplemental SAR, however, EOP-003-1 needs further revision to focus this standard solely on manual loadshed. References to the development of both UFLS and UVLS programs need to be removed from EOP-003-1 as PRC-006-1 will cover automatic UFLS programs and a series of other PRC standards already cover automatic UVLS programs. The SDT should delete R2, R4, R7 and M1 from the posted SDT revised draft standard EOP-003-1 as part of supplemental SAR limited scope of revising requirements related to underfrequency loadshedding. In addition, the SDT should give consideration to inserting the word “manual” in front of the words “load shedding” in R3 and R5 in the posted SDT revised draft standard EOP-003-1. The Measures and Violation Severity Level sections would need to be updated accordingly.
No
Although we agree with the intent of the revisions, EOP-003-1 needs further revision to focus this standard solely on manual loadshed. References to the development of both UFLS and UVLS programs need to be removed from EOP-003-1 as PRC-006-1 will cover automatic UFLS programs and a series of other PRC standards already cover automatic UVLS programs. The SDT should delete R2, R4, R7 and M1 from the posted SDT revised draft standard EOP-003-1 as part of supplemental SAR limited scope of revising requirements related to underfrequency loadshedding. In addition, the SDT should give consideration to inserting the word “manual” in front of the words “load shedding” in R3 and R5 in the posted SDT revised draft standard EOP-003-1. The Measures and Violation Severity Level sections would need to be updated accordingly.
Yes
Yes
We agree with the concept of using the frequency time performance curves instead of discrete points. However, we would like the SDT to provide additional technical background on the methodology utilized to develop both the underfrequency and overfrequency time performance curves beyond what was discussed in the “Review of Technical Changes to Standard” section in the preface of the “Unofficial Comment Form.”
No
We agree with the concept of using the PRC-024 generator underfrequency and overfrequency tripping curves instead of discrete points. In addition, we agree with the generator size and connection threshold clarification. However, we continue to believe that this standard places a burden on the UFLS Entity to shed additional load to make up for generators which do not conform to the PRC-006/PRC-024 curves. For example, if an independent power producer did not conform with the PRC-006/PRC-024 curves, it places a burden on the UFLS Entity to potentially have to shed additional load, up to the generator’s rating, to make up for the non-conforming independent generator.
Yes
Although we agree with the revision, we disagree with carrying forward the legacy concept of using an entire Regional Entity’s footprint as an island. It is highly unlikely that the entire Regional Entity footprint would become an island. What is the technical justification for the continuation of the legacy concept of studying islands consisting of the entire Regional Entity’s footprint? In addition, similar to the concurrence that the Planning Coordinators need to reach in R5, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: “The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets.” Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R5, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: “The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission.” Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly.
No
Although we agree with the intent of this requirement, similar to the concurrence that the

Planning Coordinators need to reach in R5 & R13, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: “The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission.” Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R5 & R13, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: “The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets.” Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly.
No
Although we agree with the intent of these requirements, the assessment required in R11 & R13 should only be completed for significant UFLS events. Similarly, the significant event concept should be applied to the islanding criteria in R1. In fact, the SDT mentions this concept in the “Review of Technical Changes to Standard” section in the preface of the “Unofficial Comment Form.” In the aforementioned section, the SDT uses a 500 MW qualifier which states “…resulting in 500 MW or greater of…” for R11 & R13 but the qualifier was not added to version 3 of the draft standard. Instead of an arbitrary 500 MW qualifier, the SDT should define islands of significance by looking at the transmission interface that feeds the potential island area and what is the IROL (Interconnection Reliability Operating Limit) for that transmission interface. If the amount of load in the island area is below the IROL limit, the island would not be considered as a basis in the UFLS program design and excluded from a UFLS assessment following a UFLS event. This significant event concept based on IROL should be included in the islanding criteria in R1 and the assessment requirements of R11 and R13. Similar to the concurrence that the Planning Coordinators need to reach in R13, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: “The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets.” Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R13, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: “The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission.” Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly.
Yes
Group
FirstEnergy
Sam Ciccone
FirstEnergy Corp.
Yes
No
Since we do not agree with some of the standard requirements, we therefore do not agree with

the measures for some of the requirements as written.
No
Since we do not agree with some of the standard requirements, we therefore do not agree with some of the VSL for the requirements as written.
Yes
Yes
While we agree with the inclusion of the EOP-003 in this project, the versioning and requirement language adjustments requires coordination with the proposed revision of EOP-003 that is taking place with the Order 693 Directives work Project 2010-12.
Yes
While we agree with the inclusion of the EOP-003 in this project, the versioning and requirement language adjustments requires coordination with the proposed revision of EOP-003 that is taking place with the Order 693 Directives work Project 2010-12.
Yes
Although we agree with the revisions to EOP-003 with regard to removal of underfrequency load shedding references, we believe the SDT could have improved the standard even further by developing a complete set of measures. There are currently only two measures for eight requirements. Furthermore, since EOP-003-1 is the current approved standard, and this standard would be version 2 (EOP-003-2).
No
We support the applicability section of the standard as asked per this question. However, we do not see any question for general comments and have comments and suggestions regarding the proposed implementation plan for the applicable UFLS entities and Transmission Owners that own Elements identified in the UFLS program. 1. Although we agree that the Planning Coordinator is the appropriate functional entity to develop and implement a UFLS program, we are concerned with the fact that UFLS entities may not know the specifics of their responsibilities until long after this standard is approved. The SDT should consider adjusting the language of the standard to require more transparency and coordination with the UFLS entities during the PC's development of the UFLS program. Also, per the implementation plan, the PC will be given one year to develop its UFLS program. However, the timeframe for the UFLS entity is based on the schedule imposed by the PC. The implementation plan should allow the UFLS entity at least one year (maybe more per capital budget cycles) from the time the PC identifies the UFLS entity in their UFLS program. The UFLS entity will need sufficient lead time in those instances that require purchase of new UFLS equipment that will require long term budget planning for implementation. 2. The UFLS entities are identified in the UFLS program established by the PC. However, it is not clear where the PC is explicitly required to notify and coordinate with the UFLS entity. In Requirement R3 it is implied that the PC will notify and coordinate with the UFLS entity per the phrase "including a schedule for implementation by UFLS entities within its footprint". This requirement needs to be more explicit that the PC will notify the UFLS entity, and the measure for R3 needs to require proof that the PC has done this.
No
We are concerned about the coordination between this UFLS SDT and the GV SDT. It will be difficult to approve and begin implementing the PRC-006-1 standard while the PRC-024-1 standard is still under development and scheduled for approval and implementation at a much later date. For these requirements to be adequately coordinated, the two standards need to be developed, balloted and implemented at the same time. Alternatively, consider adding the following statement in the PRC-006-1 Implementation Plan: "The Effective Date and implementation of this PRC-006-1 standard requires coordination with standard PRC-024-1. Excluding requirement R1, the Effective Date of PRC-006 shall be the later of 1) the completion of the Implementation Plan for PRC-006 or 2) the completion of the Effective Date of the PRC-024-1 standard upon completion of its Implementation Plan."
No
See our concerns in Question 9 about the coordination between this UFLS SDT and the GV SDT.
We defer an opinion on this and leave it to the Planning Coordinators to decide if this requirement is feasible for them to implement.
No
FE questions the need for this requirement and the Applicability Section item 4.3. FE asks that the SDT provide some examples of the reliability need related to frequency control for this requirement. If high voltage and automatic capacitor bank switching is the issue we don't believe that rises to a need as a reliability requirement within a UFLS standard. Voltage control should remain a separate issue from controlling frequency that this standard aims to address. Load shedding associated with UFLS is just one of many reasons why proper voltage control - through automatic Element switching of a capacitor bank - would be needed for the transmission system. If there are other technical reasons for this requirement please clarify.

We defer an opinion on this and leave it to the Planning Coordinators to decide if this requirement is feasible for them to implement.
Yes
Individual
John O'Connor
Progress Energy - Carolinas
Yes
We agree with proposed VRFs. However, we would recommend the VRF Tool be used to validate these.
No
For M3, it is unclear what is meant by the phrase “including the criteria itself.” Since the criteria is specified in R3, we recommend this phrase be deleted from the measure. For M5, this measure should only apply to Planning Coordinators (PCs) who are part of a joint island, but it is written such that it appears to apply to all PCs. We recommend rewording M5 to “Each Planning Coordinator shall have dated evidence…that it reached concurrence with the other affected PCs on design assessment results for any islands in accordance with Requirement R5 and identifies the affected PCs.” We also recommend that R5 be reworded to “Each PC shall reach concurrence with all other affected PCs on UFLS design assessment results before design assessment completion for any islands identified by that PC which include a portion of that PC's footprint along with another PCs footprint.”
No
For R4, the VSLs should include a consideration of the timeliness of the completion of the required study (e.g. lower VSL for 3 months late, Moderate for 3-6 months late, etc.). For the R11 VSLs, we recommend that the time ranges for the VSLs be expanded to allow more than one month between Low, Moderate, High and Severe. We would suggest revising to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months past the 12 month requirement.
No
Requirements R5 and R13 require Planning Coordinators (PCs) from two or more areas to agree on assessment results. However, no process is provided in the event that the PCs cannot agree. One party may have larger margin requirements or a different methodology and these differences may not be reconcilable. Therefore, it is possible that multiple PCs could be prevented from meeting the agreement requirement through no fault of their own. There needs to be a process for resolving this. We recommend that R5 include “If concurrence cannot be reached, an individual PC in the applicable island may demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply that PC’s individual scheme to the entire island.” Also, we recommend that R13 be deleted since R11 would effectively require these actions for multi-PC islands.
Yes
Yes
Yes
Yes
We recommend that R3 be revised to specifically require the Planning Coordinator to notify the “UFLS entities” in their PC area that they are part of the PC’s UFLS program.
Yes
The curves added as Attachments 1 and 2 are excellent. However, it would be helpful if a footnote to the curves provided the values of the “transition points” or breakpoints of the curves. For example on Attachment 1, there appears to be transition point at 60 seconds/58.85 Hz, but it is difficult to read exactly.
Yes
We agree with respect to the Planning Coordinator simulation requirements for modeling as stated in R4. However, the UFLS standard has no requirement for the Generator Owners to provide this information. We have been told that this might be included in PRC-024 (currently under development). This should be a condition for approval of PRC-006. Additionally, the Generator Owners should be required to notify the PC of any Manual (i.e. operator actions) that would result in a trip above/below the specified generator curves of Attachments 1 and 2. It is recognized that manual operator actions would typically be later than the approximately 60 seconds or less simulation times that a PC would use. However, this information regarding manual trips would be necessary for appropriate planning.

No
See above comments to Questions #2 and #4.
Yes
It is not clear what would be included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching out of a capacitor bank to avoid overvoltage when designed as part of the UFLS scheme). R10 refers to “Elements” and M10 refers to “Facilities”. Revise to make consistent. In both R9 and R10, replace the word “provide” with “implement.”
No
As per our comment to Question #4, we recommend R13 be deleted. The 500 MW limitation discussed in the background section of the comment form should be included in R11. There is no need to require assessments for smaller islanding events.
Yes
Group
Southern Company Transmission
JT Wood
Southern Company
Yes
We recommend that the VRF Tool be used to validate the proposed VRFs.
No
M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that it be deleted. M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. Recommend that the wording in M5 be changed to: "Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified islands in accordance with Requirement R5 and identifies the affected Planning Coordinators." Recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint."
No
The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented." The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.).
No
R5 and R13 seem very problematic. The standard requires that both or all the entities agree. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two companies cannot agree. We recommend that the following language be added to R5: “If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island.” We recommend that R13 be eliminated since it is covered by R11.
Yes
Yes
Yes
We recommend that R3 be revised to require the PC to specifically notify the “UFLS Entities” in their PC area that are part of the PC’s UFLS program.
Yes
Yes

No
see above comment to questions #2 and #4.
Yes
It is not clear what is included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching of a capacitor to avoid overvoltage). R10 refers to “Elements” and M10 refers to “Facilities.” In both R9 and R10, replace the word “provide” with “implement.”
No
As noted in our response to question #4 above, we recommend elimination of R13. The 500 MW limitation discussed in the background section should be included in R11. There is no need to evaluate smaller islanding events.
Yes
Individual
Greg Rowland
Duke Energy
Yes
However we have identified an issue with R5 and R13 requiring that Planning Coordinators “reach concurrence” which brings their VRFs into question. This is discussed further in our comments below.
No
M3 – it is unclear what is meant by the phrase “including the criteria itself”. Suggest deleting the phrase. Also, requirements R5 and R13 (and hence their Measures and VSLs) are problematic, since they require that Planning Coordinators shall “reach concurrence” with all other affected Planning Coordinators, which may not always be possible. The requirements need to provide for that situation.
No
See comment to question #2 above.
Yes
Yes, except for the issue on “reaching concurrence” identified in our response to question #2 above (R5 and R13).
Yes
Yes
Yes
Yes
Yes
Yes
No
See comments above on questions #2 and #4.
No
We question whether/how this requirement would apply to a Transmission Owner who has UFLS on distribution circuits. It’s unclear to us how this would be determined by the Planning Coordinator.
No
R11 and R12 are okay, but R13 contains the problematic requirement to “reach concurrence”, as discussed in our responses to questions #2 and #4 above. Perhaps R13 could be revised to require affected Planning Coordinators to share event assessment results and respond to technical questions/comments within a prescribed time period.
Group
MRO’s NERC Standards Review Subcommittee (NSRS)
Joseph DePoorter
Midwest Reliability Organization

No
The VRFs for R3, R4, R9, and R10 should be reduced from “High” to “Medium” for several reasons. [1] Automatic UFLS programs are system preservation measures of last resort that may help the BES recovery if the primary system preservation measures are insufficient. So, the risk to the system reliability is low because primary measures will normally restore the system even if some UFLS requirements are not completely fulfilled. [2] System events that would activate automatic underfrequency load shedding have been very rare. So, the risk to system reliability is low because events of unacceptable underfrequency rarely occur even if the sum of the UFLS requirements not completely fulfilled. [3] Automatic UFLS programs can only be designed to help preserve the system for a wide range of, but not all, possible system conditions. So, the risk to system reliability is low because UFLS programs may help for many system condtions, even if some of the UFLS requirements are not completely fulfilled. [4] For R4, the performance of the UFLS program and the characteristics of the associated islands change only slightly and gradually over many years. So, the risk to system reliability would not change dramatically if conducting or documenting of a UFLS design assessment was delayed by several years.
No
Suggest that the measures be modified to reflect any changes made to standards Requirements per the comments made to questions Q4 through Q13. M10 – Replace “automatic switching of Facilities” with “automatic switching of Elements” to be consistent with the associated Requirement R10.
No
Most of the VSLs are okay. However, the VSLs for R5 and R13 depend on reaching “concurrence” with other entities, which is not a valid basis for measuring compliance. If the concurrence requirement is not revised as suggested below, then we propose that the VSL levels be reduced.
Yes
Although THE NSRS agrees with changing the applicability of the requirements from groups of Planning Coordinators to each Planning Coordinator, the present wording in R2.3 says that for a PC with a part of its footprint in more than one region, “each of those Regional Entity footprints shall be identified as an island.” We propose that the wording be revised to require a PC with part of its footprint in more than one region to identify only those appropriate parts of its area that are in islands, not the entire Registered Entity footprint where it may be present.
No
We propose that the scope of the SAR be revised to call for removing all of the automatic UFLS requirements from EOP-003-1 and moving them to PRC-006-1 standard because no automatic load shedding system requirements should be in the EOP standards. We also note that a separate SAR should be initiated to call for the removal of all the automatic UVLS requirements from EOP-003-1 and moving them to a new PRC standard for the same reason.
No
In line with the comments for Question 6: R2 - remove this requirement because it refers to automatic load shedding plans and let the automatic requirements be covered by PRC-006-1 and a new PRC standard. R3 – Recommend R3 be rewritten to read: Each Transmission Operator and Balancing Authority shall provide manual load shedding plans to adjacent interconnected Transmission Operators and Balancing Authorities.
Yes
No
1. In R3, simply say that the “program shall shed at least 25% of island load” and avoid use of the formula. If the formula is retained, then we suggest that it be changed to the more common industry nomenclature of “imbalance = (load-generation)/generation.” 2. In R4, we interpret that the Equivalent Inertia Analysis is a valid dynamic simulation methodology for certain aspects of UFLS assessments. This is a methodology that is often recommended in relay application guides and other technical references. Please clarify that this type of dynamic analysis would be accepted toward compliance with the “through dynamic simulation” portion of this requirement. For Attachment 1 (R4.1, R4.2 & R4.3) and Attachment 2 (R4.4, R4.5 & R4.6) 3. Attachment 1 and 2 include transient frequency performance curves for at least 30%, 40% and 50% island imbalance. Otherwise, revise the titles for Attachments 1 and 2 to clearly qualify that the transient frequency performance curves apply for a 25% or less island imbalance and that programs which are larger than this minimum load shedding requirement do not have to meet this criteria when overloads are in excess of 25%. In addition, UFLS programs that are designed for appropriate performance under imbalance conditions above 25% will not have the same performance curves as programs that are designed for imbalance conditions of 25% or less. 4. If item #3 is not adopted, then the Under Frequency Performance Characteristic line in Attachment 1 should be extended from the knee at approximately 58.9 Hz (for 60 seconds) to 59.3 Hz or 59.5 Hz (for approximately 500 sec). The purpose is to define a single line of constant slope and to get rid of the arbitrary knee in the characteristic curve which serves no reliability purpose. The

reason for this change is that the worst case frequency recovery time for frequencies between 58.7 Hz and 59.5 Hz may occur for imbalance conditions significantly less than 25% where the governor response prevents the load shedding blocks from picking up and where frequency recovery times are a function of governor response and system inertia. Likewise, it makes sense to extend this line below 58 Hz to at least as low a frequency as is covered by the generation protection curve. 5. Add a note to Attachment 1 that states, "Larger size UFLS programs (e.g., 40%) may require less restrictive (lower) underfrequency (as well as and/or longer time delays) due to island generation and protection characteristics. UFLS programs shedding more than 25% must also increase generation protection delay times and/or change set points to achieve coordination with load shedding. For example, Manitoba Hydro and Saskatchewan need to shed more than 30% of the area load to achieve reasonable frequency recovery in their islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable. Generator Underfrequency and Overfrequency Coordination Attachments 6. The Generation Owner off-nominal frequency coordination requirements and coordination curves should be included only in the PRC-006 standard and not the PRC-024 standard. The generator coordination curves relate directly to the PRC-006 assessment requirements and the PRC-006 curves will be duplicative of, and possibly contradictory to, the curves in the PRC-024 standard if they are finally approved and then changed in the future. 7. The generation coordination curves need to be appropriate for the different types of UFLS programs (e.g. 25%, 30%, 40%, 50%, etc.) that have, or will be, designed and implemented for different islands. Generation coordination curves for 25% UFLS programs will not be the same for other (e.g. 30%, 40%, 50%) UFLS programs. It can be demonstrated that as the size of the load shedding program is increased, the generation protection settings have to be modified accordingly to achieve the coordination objectives. UFLS programs that are designed for imbalances greater the 25% inherently require lower minimum frequencies and longer frequency recovery times 8. If item #7 above is not adopted, then revise the titles for generation coordination curves to clearly qualify that they apply for a 0% to 25% island imbalance and that programs which are larger than this minimum load shedding requirement do not have to meet this criteria when overloads are in excess of 25%. The generation protection line should extend to 57 Hz (at .3 sec) to 59.5Hz (at 1800 sec). The minimum frequency of 57.0 Hz was chosen because most conventional generation can briefly operate down to 57.0 Hz and large load shedding programs may need to make use of that capability to achieve coordination with these UFLS programs. 9. We are aware of the technical basis for the generator Under Frequency protection setting, but not aware of the technical basis for the presently proposed generation coordination curves in PRC-006 or PRC-024. We suggest that the SDT provide the industry with the technical basis for the generation coordination curves. We are concerned that the curves allow enough time for load shedding to operate under “worst case conditions”, and as much time as possible needs to be given for frequencies close to 60 Hz. We are also concerned that for actual UFLS events system frequency recovery may stall below 59.5 Hz for a long time while operators try to deal with event with manual shedding of load. Volts/Hertz Performance Characteristic 10. The Volts/hertz requirement is not needed in this standard and should be removed for several reasons: [1] Voltage regulators automatically reduce voltage according to volts per hertz when in the automatic mode so they self protect. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist that adequately address the volts/Hz issue. [2] If voltage regulators are in automatic, then the 110% volts/Hz limit becomes active between 57.2 Hz and 51.8 Hz assuming the voltage regulator holds terminal voltage within the allowed 1.05 p.u. to 0.95 pu range. [3] Units with voltage regulators in manual will just trip when volts per Hertz protection picks up. However, units are normally in the automatic control mode per NERC Standards. [4] It appears this requirement is appropriate for programs which may experience frequencies below 57.2 Hz, but few, if any, programs are expected to be designed for frequencies that are this low. [5] Even if UFLS programs are designed for frequencies below 57.2 Hz, this performance characteristic cannot presently be properly simulated in stability cases as the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation
Yes
No
Replace the words “reach concurrence with” with “provide UFLS design assessment results to”. Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words “other affected Planning Coordinators” with “other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of “other affected Planning Coordinators” is too vague and could be interpreted and categorized differently by various entities and auditors.
No
The NSRS basically agrees with the concept that owners of automatic switching elements provide

control in accordance with the UFLS program requirements. Therefore, [1] consideration should be given to replacing “Transmission Owner” with “UFLS entity” because the automatic switching of distribution Elements (e.g. capacitor banks) may be more effective and practical in UFLS program design than restricting the scope of the requirement to just transmission Elements.[2] And consider replacing “UFLS program” with “UFLS program requirements”.
No
1. For R11, replace “Each Planning Coordinator, in whose footprint . . . to evaluate” with “When a disturbance event occurs in a Planning Coordinator’s footprint that involves automatic UFLS program operation or frequency excursions that should have activated UFLS program operation, and a final disturbance report is required per EOP-004, each Planning Coordinator shall evaluate within one year of the disturbance event:”. 2. We have concerns about specifying that the evaluation must be complete within one year we know that some historical studies of events that included UFLS took longer than one year [e.g., three years] to complete. Therefore, we would prefer a more flexible wording, a longer time frame to be used in this requirement. Perhaps the requirement could stipulate that the evaluation must begin within 6 months and be completed within the schedule set by the investigative team. 3. For R13, replace “in whose footprint . . .on the event assessment result” with “that conducts an UFLS design assessment (per R12) for islands where other Planning Coordinators have design assessment responsibilities shall provide a design assessment report to those Planning Coordinators.” The reference to the event assessment report should be part of R11. The qualification of “event affecting multiple Planning Coordinators” is too vague and could be interpreted and categorized differently by various entities and auditors. 4. R11.2, change the wording to replace “effectiveness of the UFLS program” with “conformance with UFLS program design”. Because no UFLS program can be designed to be effective for all possible contingency scenarios but should be effective for the contingency scenarios for which it was designed.
Yes
Group
ReliabilityFirst Engineering Staff
Art Buanno
ReliabilityFirst Corp.
Yes
Yes
Yes
Yes
No response seems applicable.
Yes
Yes
Yes, the revisions that were made are appropriate. However, EOP-003 will require further substantial revisions as many of the requirements are still inappropriately assigned to the TOP such as establishing automatic undervoltage load shedding plans (R2).
Yes
No
1. It is not clear how the PC is supposed to enforce performance characteristic 3.3. Part 3.3 is written based on general over-excitation limits for generators and transformers. However, entities should already have over-excitation protection on critical equipment. Isn’t the owner obligated to protect its equipment? Also, V/Hz at a bus is not a standard output of dynamic stability programs making it difficult to ensure compliance to part 3.3. It would be more useful if part 3.3 was expressed in terms that are commonly available such as voltage. Additionally, the meaningful per unit voltage is the machine or equipment base and the results would need to be scaled from the system base voltages. 2. The reliance on curves in Attachments 1 and 2 is imprecise. The frequency and time coordinates of each change in slope should be given so that entities do not need to interpret it themselves. 3. The standard relies too heavily on the possible implementation of proposed standard PRC-024. 4. The proposed PRC-006-1 UFLS standard and companion PRC-024 establish tightly defined performance characteristics which at best will just barely work for 30% UFLS programs using 3 steps of 10% load shedding. More precisely, it works for a 30% UFLS program for a range of conditions, but not for all of the conditions that can exist or are expected to exist in various portions of ReliabilityFirst over the next five years.

Thus, ReliabilityFirst staff believes that these performance characteristics coupled with declining governor response and declining equivalent inertia in the Eastern Interconnection, will encourage a redesign of one or both of the existing 30% UFLS programs within ReliabilityFirst.
No
It is not clear how the PC will determine which generating units are non-conforming as there is no requirement for the GO to provide this information in this standard. In a best case, it relies on the adoption of proposed standard PRC-024.
Yes
Yes
Yes
Yes
Group
Pepco Holdings, Inc. - Affiliates
Richard kafka
Pepco Holdings. Inc.
No
See response to question 7. PHI does not concur with the requirements as written.
No
We do not concur with the requirements as written
No
We do not concur with the requirements as written, so this activity is premature.
No
The SDT has essentially defined groups by requiring concurrence.
Yes
Yes
No
R2.3 appears to require a PC that is involved in more than one region to have an "islanding program" for its footprint in each region. What if the PC is PJM and there is a sliver a region outside RFC. Do we really need a program for the sliver? This requirement assumes without justification that RE boundaries and PC boundaries define potential islands. R4 - What is a "design assessment"? Why not just require "an assessment every five years"? Why all the extra words like "design assessment"? "conduct and document"? through dynamic simulations? R5 requires concurrence among PCs. My view is that a requirement must be to one and only one functional entity. More than one entity causes questions as to who is non-compliant when things go awry. In R5 who is non-compliant if a peer PC does not concur? R6 Why not just require a database for UFSL data? Why must the requirement include the editorial requirement "for use in Event Analysis and assessments of UFLS program" Does that mean I MUST use the UFLS database for Event Analysis? Does it mean I can't use the data for other activities? R8 is curious to me. It stipulates that the data is provided "to support the database". I ask, isn't the data being required to support the concept that the UFLS program is up-to-date and operational? For both R6 and R8, the issue is editorial explanations in addition to the actual requirement. R12 seems to say that PC whose assessment shows a problem, that PC shall conduct an assessment (again?). The requirement then goes on to mandate the PC "consider" the deficiencies. I know what they want to say but this requirement doesn't say it to me. Can you imagine proving you "considered the deficiencies"?
Yes
Yes
Yes
No
It is difficult to see how this change corrected the described problem.
Yes

Yes
Yes
Individual
Dan Rochester
IESO
No
If the Planning Coordinator does not develop and document criteria, how will other Requirements be satisfied? For this reason, the VRF for R1 should be higher.
No
The measures that refer to Requirements with subrequirements (e.g. R2, R3, and R4) should be more consistent. All of the corresponding Measures (e.g. M2 and M4) should include the final phrase: “including the criteria itself” or none should include this phrase.
Yes
Yes
Yes
Yes
Yes
No
Generator owners are not included in the Applicability Section of this standard. We understand from the SDT’s responses to the last posting that there is a separate project for generator requirements that would obligate them to provide the required information to the Planning Coordinators with which to design the underfrequency load shedding program. Absent that standard, a Generator Owner has no obligation to provide the necessary data to the Planning Coordinators which can result in the Planning Coordinator failing to meet the PRC-006-1 standard. We therefore request that Generator Owner be included in the Applicability Section and a requirement for it to provide the needed information to the Planning Coordinator be added, or balloting of standard PRC-006-1 be deferred until such a requirement in that other standard is ready for balloting. The reason for including Transmission Owners in Section A 4.3 after they have been identified in Section A 4.2 is unclear or not needed.
No
If the overfrequency characteristics are retained, it would be better to combine Attachment 1 and Attachment 2 into one curve. The curves without some explanation may not be consistently interpreted. Should the level line at the shortest times (e.g. < 2 s) and vertical line at the longest time (e.g. > 60s) for the Performance Characteristic be interpreted to mean UFLS tripping is permitted without delay below 58.0 Hz and is not permitted above 59.3 Hz?
No
The SDT should clarify the characteristics define where the generators are not permitted to trip rather than define where generators must trip. Correspondingly, it should be clarified for loads, the requirement defines the outer perimeter where UFLS loads must be tripped rather than to define where UFLS loads trip. The phrase; “directly connected to the BES” could be problematic. In the IESO-controlled grid most generators are connected to transmission system with a main output transformer. At many large generating stations, the low voltage bus of these MOTs where the generator is directly connected is not part of the BES while the high voltage bus is part of the BES. A restrictive interpretation of the present wording of the standard would limit applicability to only generating units captured under §R3.3.3, What interpretation of “directly connected” was intended by the SDT? Elements of this continent-wide standard are viewed by the IESO as a means to improve reliability not as a justification to weaken existing good practices. Does the STD support retaining existing more stringent standards (e.g. lower underfrequency thresholds and higher overfrequency thresholds or both) for generating units at the Regional or Planning Coordinator level? For example, the IESO-controlled grid mandate generating units > 10 MW and generating facilities > 50 MW directly connected to the IESO-controlled grid to have generator protection set at a level such that they do not trip over the NPCC criteria for generator underfrequency curve. We need to seek the SDTs view on whether these conditions are sufficient to satisfy the intent of the PRC-006 standard. The response of the SDT to the earlier question (see below) concerning the need for overfrequency settings as part of this standard was not satisfactory as new requirements should have a strong motivation. Our Area experienced

frequency excursions above those proposed in this standard without material adverse effects. Generation trips at these frequency levels in 2003 would have been inconsistent with the purpose of providing last resort system preservation measures. What are these referenced withstand capabilities and are they applicable to all types of units? What evidence is known to the SDT that units experience a significant loss of life due to the events on August 14, 2003 now that more than six years has passed? Why does the SDT believe overfrequency thresholds are necessary to fulfill the Purpose of this standard? [Response: Thank you for your comments. The SDT has developed the overfrequency characteristic in Requirement R6.3 to coordinate with the overfrequency trip setting limits proposed in PRC-024. The trip setting limits were developed by the Generator Verification SDT based on the withstand capabilities of generating units. The concern with operation of generating units at off-nominal frequency is the cumulative fatigue effect, so it is possible that generating units experienced significant loss of life on August 14, 2003 even if the adverse effects were not readily observable immediately after this event.]
No
The requirement to reach concurrence is outside of the capability of any single Planning Coordinator as concurrence requires at least two Planning Coordinators. The SDT should consider reformulating this requirement in terms of the actions it believes each Planning Coordinator must perform to reach concurrence with its fellow Planning Coordinators.
No
The STD may wish to consider reworking R10 in a format that matches changes to applicability. Within the IESO footprint, low voltage capacitors may be switched as part of the ULFS program. In some cases, these capacitors would below to Distribution Providers rather than Transmission Owners. “Each UFLS entity shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint.”
No
Small islands and frequency excursions below the initializing set points can result from recognized contingencies. In some cases, the island formed will be so small as to provide no meaningful evaluation for UFLS program effectiveness. Some additional guidance from the SDT is needed to define the nature of events that are intended to trigger an evaluation under R11.
Yes
Group
Tri-State Generation & Transmission Assoc.
Bill Middaugh
Bill Middaugh
No
Comments: Generally, our primary concern is that the requirements should not apply to individual Planning Coordinators, so it is difficult to agree with any proposed Violation Risk Factors (VRF). The reliability basis for R1 and R2 is not clear and we would recommend eliminating those requirements along with their VFRs. We believe the use of Transmission Owner in R10 is redundant with R9 and “switching of elements” should be merged into R9 and R10 can be eliminated. The five-year assessment in requirement R4 seems like a higher VRF than necessary and Medium would be adequate.
No
Comments: The measures are vague and not performance based leaving much up to interpretation. Measures should contain specific targets or specifications that clarify how an entity will be audited and measured for compliance. These measures merely repeat the requirements and do not provide any useful guidance beyond what is specified in the requirement itself.
No
Comments: We believe that individual Planning Coordinators are not the appropriate entities to be responsible for determining criteria for areas that may form islands, for identifying the islands, for developing the UFLS program, for periodic assessments, for maintaining databases, or for assessing events. Further, Planning Coordinator footprints are neither defined nor is there any guidance on how they should be established. Every VSL that refers to a PC footprint should be clarified. What is meant by “annually maintain” is neither clear nor defined. The VSL for R6 should be re-written. The increment size between VSLs seems arbitrarily small in R9 and R10. Is there a reliability basis for choosing 5%?
No
Comments: Individual Planning Coordinators are not the entities to determine how islands should be formed, unless the Regional Assurer is required to become the only remaining Planning Coordinators, which would be acceptable. The current registration by numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. All Planning Coordinators within an interconnection should be required to collaboratively develop an Interconnection Coordinated UFLS Plan. UFLS works on interconnection

basis not on PC footprint basis. We believe that the Regional Assurer will be better able to manage UFLS programs to the extent that the standard clearly lays out what must be accomplished. The primary purpose of any UFLS program is to mitigate the need to form islands by balancing total system loads and resources. It is only a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding events rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts within the interconnection. Again, we believe that the Regional Assurer will be better able to manage UFLS programs to the extent that the standard clearly lays out what must be accomplished We strongly believe that this should remain the responsibility of the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate or address the interconnection reliability needs.

Yes

No

Comments: The revisions are adequate for the most part, but Requirement R4 needs to specify that only undervoltage load shedding is being addressed. There is also a concern that EOP-003-2 is currently being balloted based on changes made as a part of the Order 693 Directives. The two versions are not compatible.

No

Comments: We believe that “ownership” should be removed from the criteria because it may be different from the operating or controlling entity and both entities cannot be responsible. Load Serving Entities should also be included as a “possible” UFLS entity Some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. This should remain the responsibility of the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate nor address the interconnection reliability needs.

No

Each interconnection should establish discrete set points based upon stability and dynamic analysis. From discrete set points one can establish criteria which are measurable and performance based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC. Furthermore, the Standard needs to be very explicit that the curves are interconnection performance curves and not specific protective relay set points. It is recommended to combine Attachment 1 and Attachment 2 (which contain discrete set points) into a single graph, making frequency the abscissa, and requiring simulations to maintain frequencies inside the resulting envelope. R3.3. While the concern for loss of additional generation units because of their V/Hz protection schemes is understood, the bases for the 1.18pu and 1.1pu values are not evident and may not be technically supportable when compared against actual protection settings or allowable post-contingency voltage bands. Further, V/Hz protection settings vary across the system and it is unlikely adherence to this requirement will impact reliability. It will only increase dynamic analysis requirements. We recommend removing R3.3.

No

Comments: Underfrequency is an issue of load and generation balance. It does not make sense to make the distinction of whether or not a generator or generating facilities directly connect to the BES. The loss of sizable generation has the same impact on frequency regardless of what voltage it was connected at. The thresholds used in the standards are registration thresholds for the GO/GOP function. There is nothing that would prohibit a PC, TO or TOP from establishing interconnection requirements for smaller generators that require compliance with an UFLS program if it was important to reliable BES operation

No

Comments: Elimination of Requirement R4 is acceptable; however, we believe that individual Planning Coordinators are not the entities to determine how islands should be formed. The current registration by numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. R2.3 seems to require each Planning

Coordinator to ultimately divide into multiple islands or separate its transmission system from all other transmission systems as its own island. Part of the purpose of the UFLS program should be to mitigate the need to form islands by balancing total system loads and resources. It is an additional function to balance the loads and resources after the islands have been formed. We recommend eliminating R2.
No
Comments: Since “UFLS entity” already includes Transmission Owners, requirement R10 is unnecessary and “automatic switching of Elements” ought to be combined into R9 from R10 and then R10 can be deleted. UFLS programs should be developed by the Reliability Assurer, not individual Planning Coordinators.
Yes
Comments: The concept is correct but we believe an individual Planning Coordinator is the wrong entity to assess the operation and revise it. There is no clear jurisdiction for a PC. This should remain the responsibility of the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area. Why is “of UFLS actuated loss of load occurs” included in R13 but not in R11? It does not seem to add any information but does seem to unnecessarily complicate the requirement. This again seems like an argument for having the Regional Assurer involved because concurrence between Planning Coordinators is required. The language is unclear in R13 and should be re-written.
No
Comments: The standard should adequately recognize the performance characteristics of different type of generation and a variance should not be required. Faster acting and greater inertia systems should be allowed the operating margins appropriate to their systems. Real differences exist between interconnections. The standard and its performance requirements should reflect this fact. This would allow for the uniqueness of each interconnection to be addressed similar to Hydro Quebec’s variance.
Individual
Darcy O'Connell
The California ISO
No
Cannot support approval until the requirements are closer to being finalized.
No
Cannot support approval until the requirements are closer to being finalized.
No
Cannot support approval until the requirements are closer to being finalized.
No
1) Applicability of the proposed Standard PRC-006-1 should also apply to Load Serving Entities (LSEs) for underfrequency load shedding. 2) Applicability of the proposed Standard PRC-006-1 should also apply to Generator Owners since GOs would need to be involved for overfrequency generation tripping. 3) Applicability of the proposed Standard PRC-006-1 should also apply to the Reliability Assurer/Regional Reliability Organization (RRO). (WECC in our case). 4) The Reliability Assurer/Regional Reliability Organization (RRO) should be the entity that coordinates the UFLS programs.
Yes
We request a WECC Regional variance for WECC to use its own set-points that are applicable to WECC members. (similar to what Hydro Quebec has done.)
Individual
Terry Harbour
MidAmerican Energy
No
The VRFs for R3, R4, R9, and R10 should be reduced from “High” to “Medium” for several reasons. System events that would activate automatic underfrequency load shedding have been very rare and automatic UFLS is a system preservation measure of last resort, not primary

system preservation measure. For R4 in particular, the performance of the UFLS program and the associated islands do not change rapidly or dramatically to warrant a “High” VRF for delayed conducting or documentation of a UFLS design assessment
No
Ensure that measures correctly reflect modified requirement changes. In addition there are concerns with the addition of requirements and measurements to reach concurrence. This potentially subjects an entity to non-compliance based on events beyond that entity’s control such as a problematic neighbor that refuses to reach concurrence. This concpept should be removed and replaced with a requirement to distribute the results. Examples include M5 - As noted in the comments below for R5, replace the words “reached concurrence with” with “provided a UFLS design assessment report to”. Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words “other affected Planning Coordinators” with “other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of “other affected Planning Coordinators” is too vague and could be interpreted and categorized differently by various entities and auditors. M7 – As noted in the comments below for R7, replace “within their Interconnection”, with “that have design assessment responsibilities within the islands covered by the UFLS database”. Planning Coordinators that are within the same Interconnection, but are not within any islands covered by another Planning Coordinators UFLS database, would not need to receive the UFLS information. M10 – Replace “automatic switching of Facilities” with “automatic switching of Elements” to be consistent with the associated Requirement R10
Yes
Yes
No
The SAR needs to recognize that all the standards are interconnected and other existing standards development. Automatic load shedding needs to be left in PRC-006. Manual load shedding should be left in EOP-003 according to already existing standards proposed changes. The SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and referring them to a new UVLS standard or PRC-006.
No
The SAR needs to recognize that all the standards are interconnected and other existing standards development. Automatic load shedding needs to be left in PRC-006. Manual load shedding should be left in EOP-003 according to already existing standards proposed changes. The SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and referring them to either a new UVLS standard or PRC-006
No
Automatic load shedding needs to be left in PRC-006. Manual load shedding should be left in EOP-003 according to already existing standards proposed changes. The SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and referring them to a new PRC-024-1 standard. In line with the comments for Question 6: R2 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and PRC-024-1. R3 – add the qualification “coordinate manual load shedding plans”. R4 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and PRC-024-1. R5 – add the qualification “implement manual load shedding plans”. R7 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and PRC-024-1
No
The word “all” should be replaced with "applicable". The compliance requirement should focus on primary entity identified responsible for that compliance function. An example, might include a jointly owned facility (generator, substation, line, transformer, or capacitor bank) owned by one or more entities and operated by another. One identified entity should be identified and held responsible its UFLS relays whether through majority ownership, interconnection agreements, or contracts. Since ownership and operation can be divided, it is inappropriate to enforce compliance responsibilities on entities outside of their control.
No
R3.3 should be deleted as it does not directly apply. If volts / hertz requirements remain, they should be consistent with the proper IEEE standards.
Yes

No
Instead of reaching concurrence, entities should be just required to inform adjacent interconnected NERC entities of the assessment results. Otherwise entities could potentially be held responsible for inaction of another planning coordinator. The language could be changed to be consistent with the language in EOP-003 R3, such as, “Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected (entities)”.
Yes
No
MidAmerican notes that past under frequency event analyses are complex and that the minimum time frames for analysis and implementation should be increased to at least 2 years and exception requests for additional time should be allowed.
Yes
Individual
Patrick Farrell
Southern California Edison Company
No
SCE does not agree with the proposed reliability standard and, therefore, we cannot agree with the proposed Violation Risk Factors.
No
We do not agree with the proposed reliability standard and, therefore, we cannot agree with the proposed Measures.
No
We do not agree with the proposed reliability standard and, therefore, we cannot agree with the proposed Violation Severity Levels.
No
SCE does not agree with this revision and supports WECC’s position that "The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators.”
Yes
Yes
We agree in principle with the expanded scope for the Supplemental SAR.
We cannot comment on the proposed revisions to EOP-003-1, as their ramifications have not been studied in detail.
No
SCE agrees with WECC’s position that “the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered, the LSE needs to be included in the Applicability section”.
No
SCE agrees with WECC’s position that “This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections – no such justification has been provided.”
SCE is unsure of the ramifications of this change and, therefore, cannot confirm that we are in agreement with the change.
No
SCE would hope that the drafting team provides additional clarification on this requirement, as we are unsure of what the team intends by “automatic switching of Elements”.
Group

IRC Standards Review Committee
Ben Li
IESO
No
No VRF for UFLS should be High. UFLS is only actuated because several other things did not work properly. For a VRF to be High, there must be a direct causal link to bad things happening (i.e. cascading, instability, blackout) as result of the requirement. If UFLS has to be actuated, we have already reached the bad things happening stage and this represents a last ditch effort to save the system.
Yes
No
The ability for the PC to comply with R1 and R2 requires ULFS entities and Transmission Owners to comply with this standard. The VSLs should clearly state that it is the PC who did not meet its obligations under R1 and R2 and not that non-compliance to R1 and R21 was the result of non-compliance by a third party which the PC relied on into meeting its obligations under this standard.
Yes
We agree; however, this standard should not disallow the ability for some PCs to group together to develop a wide area UFLS plan. To the extent some PCs do this, the standard should be written and performance measured in a manner that does not cause these PCs to duplicate the same documents that may already be provided by another PC for the same footprint.
Yes
No
Please see comments to 7.
No
We understand the concerns that EOP-003-1 contains redundant requirements. However, the Order 693 changes include revisions to EOP-003-1 that are in conflict with the supplemental SAR.
No
Generator owners are not included in the applicability of this standard. We understand from the SDT's responses to the last posting that there is a separate project for generator requirements that could obligate them to provide required data to planning coordinators for underfrequency load shedding schemes. However, absent that standard, a generator owner has no obligation to provide needed data to a planning coordinator. If the generator owner fails to provide that data, then that planning coordinator could be found in violation of a requirement in PRC-006-1. NERC must recognize that registered entities may vote against PRC-006-1 if they are concerned about the ability to meet requirements which rely on yet to be approved or developed standards and/or definitions. Therefore, in a concerted effort to move proposed standards through the approval process, NERC must not enforce specific requirements upon a registered entity if that entity cannot meet a requirement because a supporting standard or definition is not yet in effect. We are also concerned that the ULFS standards requirements may not apply to new entities and loads that may be interconnected to the BPS such as those for Demand Response grid services. New technologies such as Smart Grid and Plug-In Electric Vehicles will become more prevalent in the near future and new entities may be aggregating these loads to offer grid services. Because it is unknown how these aggregators may be structured, they may not fall into the registered entity categories specified in this standard. NERC should be diligent in identifying new entities that existing approved standards should apply to and adjust the registry and standards accordingly.
Yes
Yes
No
We agree with the need for Planning Coordinators in neighboring regions "to identify and reach agreement on islands between its region and neighboring regions". However, we believe new problems have been introduced. First, 2.3 under R2 is arbitrary and lacks any technical basis. There is no reason for splitting a island based on regional boundaries. Additionally, we are concerned that R1 may be viewed as an attempt to predict islands that may occur. Will a PC be held non-compliant if they predict incorrectly. There requirement needs to be clear that it is intended solely for the purpose of designing UFLS "islands".
Yes

Yes
Yes

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Standards Announcement
Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2007-01: Underfrequency Load Shedding
The initial ballot for proposed standards PRC-006-1 — Automatic Underfrequency Load Shedding and EOP-003-1— Load Shedding Plans ended on July 17, 2010.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 86.94 %
Approval: 43.13 %

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Violation Risk Factor (VRF) and Violation Severity Level (VSL) Non-binding Poll Results
For the non-binding poll, 45% of those registered to participate provided an opinion; 71% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Next Steps
As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background
Major objectives:

1. Ensure UFLS programs are developed to provide an appropriate level of reliability (not least common denominator).
2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.
3. Address the issues raised by FERC Order 693 and other applicable orders.
4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

More information is available on the project page:
http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance, please contact Lauren Koller at Lauren.Koller@nerc.net

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Non-binding Poll Name:	Project 2007-01 - Underfrequency Load Shedding - Non-binding poll for VRF and VSLs
Poll Period:	7/8/2010 - 7/17/2010
Total # Opinions:	267
Total Ballot Pool:	314
Summary Results:	45% of those who registered to participate provided an opinion; 71% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Avista Corp.	Scott Kinney	Abstain	
1	Baltimore Gas & Electric Company	John J. Moraski	Abstain	
1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Negative	
1	Central Maine Power Company	Brian Conroy	Abstain	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Abstain	
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Commonwealth Edison Co.	Daniel Brotzman	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	John K Loftis	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Negative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Negative	
1	Entergy Corporation	George R. Bartlett	Affirmative	

1	FirstEnergy Energy Delivery	Robert Martinko	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	GDS Associates, Inc.	Claudiu Cadar	Abstain	
1	Georgia Transmission Corporation	Harold Taylor, II	Negative	View
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Idaho Power Company	Ronald D. Schellberg	Negative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lake Worth Utilities	Walt Gill	Affirmative	
1	Lakeland Electric	Larry E Watt	Abstain	
1	Lee County Electric Cooperative	John W Delucca		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Negative	
1	Metropolitan Water District of Southern California	Ernest Hahn	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch		
1	New York Power Authority	Arnold J. Schuff	Negative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	View
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Negative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Negative	View
1	PacifiCorp	Mark Sampson		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	Frank F. Afranji		
1	Potomac Electric Power Co.	Richard J Kafka	Abstain	
1	PowerSouth Energy Cooperative	Larry D. Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Negative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	

1	Public Utility District No. 1 of Chelan County	Chad Bowman	Abstain	
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka		
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sierra Pacific Power Co.	Richard Salgo	Abstain	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Negative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Negative	View
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Abstain	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association Inc.	Keith V. Carman	Negative	
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Jason L. Murray	Abstain	
2	BC Transmission Corporation	Faramarz Amjadi	Abstain	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Negative	View
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	American Electric Power	Raj Rana		
3	Arizona Public Service Co.	Thomas R. Glock	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blachly-Lane Electric Co-op	Bud Tracy	Negative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	

3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson	Negative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Abstain	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Constellation Energy	Carolyn Ingersoll		
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	East Kentucky Power Coop.	Sally Witt	Negative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Negative	View
3	Hydro One Networks, Inc.	Michael D. Penstone	Abstain	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Negative	
3	Lincoln Electric System	Bruce Merrill	Negative	View
3	Los Angeles Department of Water & Power	Kenneth Silver		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	Manitoba Hydro	Greg C Parent		
3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Negative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John Bos	Affirmative	

3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	North Carolina Municipal Power Agency #1	Denise Roeder		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	OTP Wholesale Marketing	Bradley Tollerson	Negative	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Negative	
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Negative	View
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	
3	South Mississippi Electric Power Association	Gary Hutson	Abstain	
3	Southern California Edison Co.	David Schiada	Negative	View
3	Springfield Utility Board	Jeff Nelson	Abstain	
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	
3	Tri-State G & T Association Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power - Ohio	Kevin Koloini	Negative	
4	American Public Power Association	Allen Mosher	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle		
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	

4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Oklahoma Municipal Power Authority	Terri Pyle	Negative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	View
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
4	Y-W Electric Association, Inc.	James A Ziebarth	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Negative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Chelan County Public Utility District #1	John Yale		
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Tallahassee	Alan Gale	Negative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad		
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Robert Smith	Negative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Green Country Energy	Greg Froehling	Abstain	
5	JEA	Donald Gilbert	Abstain	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	View

5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Negative	View
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Negative	
5	Otter Tail Power Company	Stacie Hebert	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Power LLC	David Murray	Abstain	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Abstain	
5	Salt River Project	Glen Reeves	Negative	View
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones		
5	South Mississippi Electric Power Association	Jerry W Johnson	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	Tri-State G & T Association Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Cleco Power LLC	Matthew D Cripps	Abstain	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S Slade	Abstain	

6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Negative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Negative	View
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Municipal Power Pool	Thomas E Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Louisville Gas and Electric Co.	Daryn Barker		
6	Manitoba Hydro	Daniel Prowse	Negative	
6	New York Power Authority	Thomas Papadopoulos	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	View
6	Omaha Public Power District	David Ried	Abstain	
6	OTP Wholesale Marketing	Bruce Glorvigen	Negative	
6	Progress Energy	James Eckelkamp	Negative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	South Carolina Electric & Gas Co.	Matt H Bullard	Abstain	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Negative	
6	Xcel Energy, Inc.	David F. Lemmons	Abstain	
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Abstain	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Negative	
9	Commonwealth of Massachusetts	Donald E. Nelson	Abstain	

	Department of Public Utilities			
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge		
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

Ballot Results

Ballot Name:	Project 2007-01 Underfrequency Load Shedding_in
Ballot Period:	7/7/2010 - 7/17/2010
Ballot Type:	Initial
Total # Votes:	273
Total Ballot Pool:	314
Quorum:	**86.94 % The Quorum has been reached**
Weighted Segment Vote:	43.13 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	89	1	23	0.329	47	0.671	8	11
2 - Segment 2.	9	0.8	2	0.2	6	0.6	1	0
3 - Segment 3.	76	1	20	0.351	37	0.649	8	11
4 - Segment 4.	26	1	11	0.55	9	0.45	2	4
5 - Segment 5.	57	1	19	0.396	29	0.604	3	6
6 - Segment 6.	36	1	6	0.222	21	0.778	5	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.4	3	0.3	1	0.1	1	2
9 - Segment 9.	7	0.6	4	0.4	2	0.2	0	1
10 - Segment 10.	7	0.5	4	0.4	1	0.1	0	2
Totals	**314**	**7.3**	**92**	**3.148**	**153**	**4.152**	**28**	**41**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Avista Corp.	Scott Kinney	Negative	View
1	Baltimore Gas & Electric Company	John J. Moraski	Abstain	

1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Negative	View
1	Central Maine Power Company	Brian Conroy	Abstain	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Abstain	
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Commonwealth Edison Co.	Daniel Brotzman	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	John K Loftis	Negative	View
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Negative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Negative	View
1	Entergy Corporation	George R. Bartlett	Negative	View
1	FirstEnergy Energy Delivery	Robert Martinko	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	GDS Associates, Inc.	Claudiu Cadar	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Negative	View
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	View
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lake Worth Utilities	Walt Gill	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	View
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	Metropolitan Water District of Southern California	Ernest Hahn	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	View
1	Nebraska Public Power District	Richard L. Koch		
1	New York Power Authority	Arnold J. Schuff	Negative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	View
1	NorthWestern Energy	John Canavan	Negative	View
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Negative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Negative	View
1	PacifiCorp	Mark Sampson		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	Frank F. Afranji		
1	Potomac Electric Power Co.	Richard J Kafka	Negative	View
1	PowerSouth Energy Cooperative	Larry D. Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Negative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Negative	View
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka		
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Negative	View

1	Seattle City Light	Pawel Krupa	Negative	
1	Sierra Pacific Power Co.	Richard Salgo	Negative	View
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Negative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Negative	View
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Abstain	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association Inc.	Keith V. Carman	Negative	
1	Tucson Electric Power Co.	John Tolo	Negative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	View
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Jason L. Murray	Abstain	
2	BC Transmission Corporation	Faramarz Amjadi	Negative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Negative	View
2	Southwest Power Pool	Charles H Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana		
3	Arizona Public Service Co.	Thomas R. Glock	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blachly-Lane Electric Co-op	Bud Tracy	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson	Negative	View
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Abstain	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Constellation Energy	Carolyn Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	East Kentucky Power Coop.	Sally Witt	Negative	
3	Entergy	Joel T Plessinger	Negative	View
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Power Corporation	Lee Schuster		
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Negative	View
3	Hydro One Networks, Inc.	Michael D. Penstone	Abstain	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Negative	
3	Lincoln Electric System	Bruce Merrill	Negative	View
3	Los Angeles Department of Water & Power	Kenneth Silver		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	

3	Manitoba Hydro	Greg C Parent		
3	MEAG Power	Steven Grego	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Negative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	View
3	Muscatine Power & Water	John Bos	Affirmative	
3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	View
3	North Carolina Municipal Power Agency #1	Denise Roeder		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Negative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	OTP Wholesale Marketing	Bradley Tollerson	Negative	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Negative	
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill		
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	
3	South Mississippi Electric Power Association	Gary Hutson	Negative	
3	Southern California Edison Co.	David Schiada		
3	Springfield Utility Board	Jeff Nelson	Abstain	View
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	
3	Tri-State G & T Association Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	View
4	American Municipal Power - Ohio	Kevin Koloini	Negative	
4	American Public Power Association	Allen Mosher	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle		
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Oklahoma Municipal Power Authority	Terri Pyle	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	View
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
4	Y-W Electric Association, Inc.	James A Ziebarth	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Negative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	

5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	Chelan County Public Utility District #1	John Yale		
5	City of Grand Island	Jeff Mead	Negative	
5	City of Tallahassee	Alan Gale	Negative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	View
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	Duke Energy	Robert Smith	Negative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	
5	Entergy Corporation	Stanley M Jaskot	Negative	View
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	JEA	Donald Gilbert	Abstain	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	View
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Negative	View
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Negative	
5	Otter Tail Power Company	Stacie Hebert	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Negative	View
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Negative	
5	PSEG Power LLC	David Murray	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Negative	View
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones		
5	South Mississippi Electric Power Association	Jerry W Johnson	Negative	View
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	Tri-State G & T Association Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Cleco Power LLC	Matthew D Cripps	Abstain	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S Slade	Negative	View
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit	Negative	View
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Negative	
6	Exelon Power Team	Pulin Shah	Negative	
6	FirstEnergy Solutions	Mark S Travaglianti	Negative	View
6	Florida Municipal Power Agency	Richard L. Montgomery		

6	Florida Municipal Power Pool	Thomas E Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Louisville Gas and Electric Co.	Daryn Barker	Abstain	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Abstain	
6	OTP Wholesale Marketing	Bruce Glorvigen	Negative	
6	Progress Energy	James Eckelkamp	Negative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	South Carolina Electric & Gas Co.	Matt H Bullard	Negative	View
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Negative	
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz		
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Abstain	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Negative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Negative	View
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Negative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge		
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on 3rd Draft of Underfrequency Load Shedding Program Requirements — Project 2007-01

The Underfrequency Load Shedding Standard Drafting Team thanks all commenters who submitted comments on the proposed 3rd draft of the PRC-006-1— Automatic Underfrequency Load Shedding Standard, EOP-003-1 — Load Shedding Plans, and the associated Implementation Plan. The standards and implementation plan were posted for a 35-day public comment period from June 11, 2010 through July 16, 2010. Stakeholders were asked to provide feedback through a special electronic comment form. There were 41 sets of comments, including comments from more than 100 different people from over 55 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Summary of Changes

During the third posting of PRC-006-1 and EOP-003-2 the standard drafting team made several conforming changes as a result of the industry comments received.

- The fourth version of the proposed standard addresses the coordination issue many commenters expressed. Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 require concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. Requirement R14 was added to provide peer pressure in responding to concerns about UFLS programs.
- Commenters expressed confusion over having Transmission Owners as possible UFLS Entities but separated out as Transmission Owners in Requirement R10 and suggested merging Requirements R9 and R10. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements.
- Commenters expressed that the wording in Requirement R10 “switching of elements” is confusing. The team modified Requirement R10 to clarify that it means: “switching of capacitor banks, Transmission Lines, and reactors” to control over voltage as a result of under frequency load shedding.
- Commenters suggested that R13 was unclear, and the team revised the requirement by deleting the phrase, “. . . of UFLS actuated loss of load occurs. . . ”
- Many commenters indicated that Generator Owners should be included in the applicability of the standard. Some suggested including a data requirement in PRC-006-1 that requires the Generator Owners to submit the necessary data to accomplish Requirement R4; however, the team felt that because such a data requirement already exists in PRC-024 and because the team has clarified in the effective date of the standard that the Parts of the requirement related to generators will not be effective until PRC-024 is approved and effective, that adding such a data requirement to PRC-006 would be redundant and possibly cause double jeopardy concerns.
- The phrase, “Planning Coordinator footprint” was changed to “Planning Coordinator area” throughout the standard for improved clarity.

- The team also made modifications to clarify the performance characteristics in Requirement R3.
- The team modified Requirements R6 and R7 to clarify the limit the scope of the UFLS database.

The standard drafting team received several comments on EOP-003 that expressed concern that the removal of under-frequency load shedding in the standard was not clear enough. The standard drafting team made modifications to the EOP-003 requirements that clarify that the load shedding referred to in the requirements excludes automatic under-frequency load shedding.

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Ben Eng	New York Power Authority	NPCC	4
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Dean Ellis	Dynegy Generation	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick System Operator	NPCC	2
15.	Bruce Metruck	New York Power Authority	NPCC	6

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
16.	Lee Pedowicz	Northeast Power Coordinating Council NPCC 10										
17.	Robert Pellegrini	The United Illuminating Company NPCC 1										
18.	Saurabh Saksena	National Grid NPCC 1										
19.	Michael Schiavone	National Grid NPCC 1, 3										
20.	Peter Yost	Consolidated Edison Co. of New York, Inc. NPCC 3										
21.	Chantel Haswell	FPL Group NPCC 5										
22.	Si Truc Phan	Hydro-Quebec TransEnergie NPCC 1										
2.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Charles Long	Entergy	SERC	1
3.	James Manning	North Carolina Electric Membership Corporation	SERC	3
4.	Jim Kelley	PowerSouth Energy Cooperatiove	SERC	1
5.	Pat Huntley	SERC Reliability Corporation	SERC	10
6.	Bob Jones	Southern Company Services, Inc. - Transmission	SERC	1
7.	David Marler	Tenessee Valley Authority	SERC	1

3.	Group	Bob Jones, Chairman	SERC SC UFLS Standard Drafting Team	X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Foster	Ameren Services Company	SERC	1
2.	Venkat Kolluri	Entergy	SERC	1
3.	Greg Davis	Georgia Transmission Corporation	SERC	1
4.	Ernesto Paon	Municipal Electric Authority of Georgia	SERC	1
5.	Andrew Fusco	North Carolina Municipal Power Agency Number 1	SERC	4
6.	John O'Connor	Progress Energy Carolinas	SERC	1
7.	Pat Huntley	SERC Reliability Corporation	SERC	NA
8.	Jonathan Glidewell	Southern Company Services, Inc.	SERC	1
9.	Tom Cain	Tennessee Valley Authority	SERC	1

4.	Group	Mallory Huggins	NERC Staff									

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Phil Tatro	NERC	NA - Not Applicable	NA
2.	Bob Cummings	NERC	NA - Not Applicable	NA
3.	David Taylor	NERC	NA - Not Applicable	NA
4.	Stephanie Monzon	NERC	NA - Not Applicable	NA
5.	Al McMeekin	NERC	NA - Not Applicable	NA

5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Vasallo	BPA, Tx Customer Service Engineering	WECC	1
2.	Rebecca Berdahl	BPA, Long Term Sales and Purchases	WECC	3

6.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
2.	Jim Detweiler	FE	RFC	1

7.	Group	Joseph DePoorter	MRO's NERC Standards Review Subcommittee (NSRS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Tom Webb	WPSC	MRO	3, 4, 5, 6
4.	Jason Marshall	MISO	MRO	2
5.	Jodi Jenson	WAPA	MRO	1, 6
6.	Ken Goldsmith	ALTW	MRO	4
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
9.	Joseph Knight	GRE	MRO	1, 3, 5, 6
10.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
11.	Scott Nickels	RPU	MRO	4
12.	Terry Harbour	MEC	MRO	6, 1, 3, 5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
13. Carol Gerou		MRO	MRO 10										
8.	Group	Art Buanno	ReliabilityFirst Engineering Staff										X
Additional Member		**Additional Organization**	**Region**	**Segment Selection**									
1. Ray Mason		ReliabilityFirst Corp.	RFC 10										
9.	Group	Richard kafka	Pepco Holdings, Inc. - Affiliates	X		X		X	X				
Additional Member		**Additional Organization**	**Region**	**Segment Selection**									
1. Dave Thorne		Potomac Electric Power Company	RFC 1										
2. Vic Davis		Delmarva Power & Light	RFC 1										
10.	Individual	Shawn Jacobs	SPP System Protection and Control Working Group		X								X
11.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
12.	Individual	Dennis Chastain	Tennessee Valley Authority (TVA)	X		X		X	X				
13.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
14.	Individual	JT Wood	Southern Company Transmission	X		X							
15.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X				
16.	Individual	John Bee	Exelon	X		X		X					
17.	Individual	Ernesto Paon	MEAG Power	X		X		X					
18.	Individual	Kirit Shah	Ameren	X		X		X	X				
19.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
20.	Individual	Robert Ganley	Long Island Power Authority	X									
21.	Individual	John Bussman	AECI	X		X		X	X				
22.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
23.	Individual	James A. Ziebarth	Y-W Electric Association, Inc.				X						
24.	Individual	Jonathan Appelbaum	United Illuminating Company	X									
25.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	Edward Davis	Entergy Services	X		X		X	X				
27.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
28.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
29.	Individual	Jeff Nelson	Springfield Utility Board			X							
30.	Individual	Charles Lawrence	American Transmission Co.	X									
31.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
32.	Individual	Claudiu Cadar	GDS Associates	X									
33.	Individual	Joe Springhetti	Wisconsin Electric Power Company (dba We Energies)			X	X	X					
34.	Individual	John O'Connor	Progress Energy - Carolinas	X		X		X	X				
35.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
36.	Individual	Dan Rochester	IESO		X								
37.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Phillips	MISO		2
2.	Patrick Brown	PJM	RFC	2
3.	Charles Yeung	SPP	SPP	2
4.	Steve Myers	ERCOT	ERCOT	2
5.	Matt Goldberg	ISO-NE	NPCC	2
6.	Mark Thompson	AESO	WECC	2
7.	James Castle	NYISO	NPCC	2

38.	Individual	Bill Middaugh	Tri-State Generation & Transmission Assoc.	X									
39.	Individual	Darcy O'Connell	The California ISO		X								
40.	Individual	Terry Harbour	MidAmerican Energy	X									
41.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X					

1. The SDT drafted Violation Risk Factors, for the requirements. Do you agree with the proposed Violation Risk Factors?

Summary Consideration:

The standard drafting team made conforming modifications to the VRF for Requirement R1 as a result of industry comments received that indicated that the VRF should be higher (changed from Lower to Medium) since the output of this requirement is used in higher VRF requirements.

Several commenters did not agree that the VRFs assigned a medium or higher are appropriate for a planning standard; however, the VRF assignments by definition apply both to operations and planning standards. In the planning timeframe the standard drafting team thinks it has appropriately assigned VRFs.

Organization	Yes or No	Question 1 Comment
Xcel Energy		No comments
The California ISO	No	Cannot support approval until the requirements are closer to being finalized.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Tri-State Generation & Transmission Assoc.	No	Comments: Generally, our primary concern is that the requirements should not apply to individual Planning Coordinators, so it is difficult to agree with any proposed Violation Risk Factors (VRF).The reliability basis for R1 and R2 is not clear and we would recommend eliminating those requirements along with their VFRs.We believe the use of Transmission Owner in R10 is redundant with R9 and "switching of elements" should be merged into R9 and R10 can be eliminated.The five-year assessment in requirement R4 seems like a higher VRF than necessary and Medium would be adequate.
Response: The SDT notes that Order 672 establishes that requirements apply to users, owners, and operators of the Bulk Electric System. The SDT thinks that the Planning Coordinator (a user, owner, operator of the Bulk Electric System) is the next most appropriate entity to fulfill the responsibilities in the proposed standard. The SDT believes the Planning Coordinator is the most appropriate applicable entity because design of a UFLS program should consider the widest possible geographic area. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role, the SDT anticipates that the Transmission Planners' expertise will be utilized. **The SDT thinks that Requirement R1 and Requirement R2 are important parts of establishing a UFLS program and are a necessary part of the proposed standard.** **Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator;**		

Organization	Yes or No	Question 1 Comment
Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements. **This requirement is assigned a High VRF because the reliability objective of this requirement is to perform an assessment of the UFLS program every five years. Violation of this requirement, by failing to validate the UFLS program through dynamic simulations, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.**		
American Transmission Co.	No	The VRFs for R3, R4, R9, and R10 should be reduced from "High" to "Medium" for several reasons. System events that would activate automatic underfrequency load shedding have been very rare and automatic UFLS is a system preservation measure of last resort, not primary system preservation measure. For R4 in particular, the performance of the UFLS program and the associated islands do not change rapidly or dramatically to warrant a "High" VRF for delayed conducting or documentation of a UFLS design assessment.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.		
IESO	No	If the Planning Coordinator does not develop and document criteria, how will other Requirements be satisfied? For this reason, the VRF for R1 should be higher.
Response: The SDT agrees with the commenter and made conforming changes to the VRF for Requirement R1.		
IRC Standards Review Committee	No	No VRF for UFLS should be High. UFLS is only actuated because several other things did not work properly. For a VRF to be High, there must be a direct causal link to bad things happening (i.e. cascading, instability, blackout) as result of the requirement. If UFLS has to be actuated, we have already reached the bad things happening stage and this represents a last ditch effort to save the system.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.		

Organization	Yes or No	Question 1 Comment
Southern California Edison Company	No	SCE does not agree with the proposed reliability standard and, therefore, we cannot agree with the proposed Violation Risk Factors.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Pepco Holdings, Inc. - Affiliates	No	See response to question 7. PHI does not concur with the requirements as written.
Response: Please see our response to your comments on Question 7. The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Long Island Power Authority	No	The VRF for R1 for the development and documentation of UFLS program criteria is stated as a "Low" VRF. Such a requirement to develop overall UFLS program criteria was more than a "Low" or Admininstrative requirement and that the VRF for this requirement should be listed as Medium VRF. The requirement to develop a program criteria in Requirement R1 is as important as those requirements stated in Requirement R2 which was assigned a Medium VRF by the DT.
Response: The SDT agrees with the commenter and made conforming changes to the VRF for Requirement R1.		
Northeast Power Coordinating Council	No	The VRF for R1 for the development and documentation of UFLS program criteria is stated as a Low VRF. Such a requirement to develop overall UFLS program criteria was more than a 'Low' or Administrative requirement, and the VRF for this requirement should be listed as a Medium VRF. The requirement to develop program criteria in Requirement R1 is as important as those requirements stated in Requirement R2 which was assigned a Medium VRF by the DT.
Response: The SDT agrees with the commenter and made conforming changes to the VRF for Requirement R1.		
Northeast Utilities	No	The VRF for Requirement R1 is stated as a Lower. The requirement to develop program criteria in Requirement R1 is as important as those requirements stated in Requirement R2 which is assigned a Medium VRF. Suggest the Requirement R1 VRF be revised to Medium.
Response: The SDT agrees with the commenter and made conforming changes to the VRF for Requirement R1.		
Manitoba Hydro	No	The VRFs for R3, R4, R9, and R10 should be reduced from "High" to "Medium" for several reasons. System events that would activate automatic underfrequency load shedding have been very rare and automatic UFLS

Organization	Yes or No	Question 1 Comment
		is a system preservation measure of last resort, not primary system preservation measure. For R4 in particular, the performance of the UFLS program and the associated islands do not change rapidly or dramatically to warrant a "High" VRF for delayed conducting or documentation of a UFLS design assessment.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.		
MidAmerican Energy	No	The VRFs for R3, R4, R9, and R10 should be reduced from "High" to "Medium" for several reasons. System events that would activate automatic underfrequency load shedding have been very rare and automatic UFLS is a system preservation measure of last resort, not primary system preservation measure. For R4 in particular, the performance of the UFLS program and the associated islands do not change rapidly or dramatically to warrant a "High" VRF for delayed conducting or documentation of a UFLS design assessment
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	The VRFs for R3, R4, R9, and R10 should be reduced from "High" to "Medium" for several reasons. [1] Automatic UFLS programs are system preservation measures of last resort that may help the BES recovery if the primary system preservation measures are insufficient. So, the risk to the system reliability is low because primary measures will normally restore the system even if some UFLS requirements are not completely fulfilled. [2] System events that would activate automatic underfrequency load shedding have been very rare. So, the risk to system reliability is low because events of unacceptable underfrequency rarely occur even if the sum of the UFLS requirements not completely fulfilled. [3] Automatic UFLS programs can only be designed to help preserve the system for a wide range of, but not all, possible system conditions. So, the risk to system reliability is low because UFLS programs may help for many system condtions, even if some of the UFLS requirements are not completely fulfilled. [4] For R4, the performance of the UFLS program and the characteristics of the associated islands change only slightly and gradually over many years. So, the risk to system reliability would not change dramatically if

Organization	Yes or No	Question 1 Comment
		conducting or documenting of a UFLS design assessment was delayed by several years.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.		
Tennessee Valley Authority (TVA)	No	TVA believes the following VRF changes should be considered: R4 - change from High to Medium. Justification: The selection of a 5-year interval for assessments seems subjective in nature. Failure to perform an assessment within a 5-year interval would not directly cause or contribute to bulk electric system instability. R11 - change from Medium to Low. Justification: documenting a post event assessment seems more administrative in nature, relative to R12.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition. **R11- A similar requirement exists in PRC-009-0 Requirement R1 and is assigned a Medium VRF. This requirement is assigned a Medium VRF because it requires assessment of UFLS equipment performance and UFLS program effectiveness during specified events involving UFLS activation that could identify deficiencies in either, and if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of the bulk electric system, or the ability to effectively control or restore the bulk electric system.**		
Western Electricity Coordinating Council	No	We agree that the proposed VRFs are appropriate for the subject of the requirements, but we do not agree with many of the requirements as drafted, so we are opposed for that reason
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
AECI	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 1 Comment
Exelon	Yes	
FirstEnergy	Yes	
Indiana Municipal Power Agency	Yes	
MEAG Power	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC Planning Standards Subcommittee	Yes	
SERC SC UFLS Standard Drafting Team	Yes	
South Carolina Electric and Gas	Yes	
SPP System Protection and Control Working Group	Yes	
Springfield Utility Board	Yes	
United Illuminating Company	Yes	
Wisconsin Electric Power Company (dba We Energies)	Yes	
Y-W Electric Association, Inc.	Yes	
Ameren	Yes	Did the SDT utilize the VRF Tool recently developed by the Process Subcommittee of the NERC SC to develop the VRFs? If not, the VRFs should be revisited using this tool.

Organization	Yes or No	Question 1 Comment
Response: The SDT did not use the VRF Tool. The use of the tool is not authorized at this time.		
Illinois Municipal Electric Agency	Yes	For R8, R9, R10 applicable to UFLS entity/TO.
Response: Thank you for your support.		
Duke Energy	Yes	However we have identified an issue with R5 and R13 requiring that Planning Coordinators "reach concurrence" which brings their VRFs into question. This is discussed further in our comments below.
Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.		
Progress Energy - Carolinas	Yes	We agree with proposed VRFs. However, we would recommend the VRF Tool be used to validate these.
Response: The SDT did not use the VRF Tool. The use of the tool is not authorized at this time.		
Entergy Services	Yes	We recommend that the VRF Tool be used to validate the proposed VRFs.
Response: The SDT did not use the VRF Tool. The use of the tool is not authorized at this time.		
Southern Company Transmission	Yes	We recommend that the VRF Tool be used to validate the proposed VRFs.
Response: The SDT did not use the VRF Tool. The use of the tool is not authorized at this time.		

2. The SDT drafted Measures for the requirements. Do you agree with the proposed Measures?

Summary Consideration:

The standard drafting team received comments to improve the clarity of the Measures and made some conforming changes to the Measures for this purpose, including the following:

- M2 and M3 - Removed the phrase, "including the criteria itself".
- M5 and M13 – Expanded the description of possible types of acceptable evidence.
- M10 – Replaced the phrase, "switching of Facilities" with a specific list of Elements.

Organization	Yes or No	Question 2 Comment
Xcel Energy		No comments
AECI	No	For M1, how can we consider historical events if we have never had a UFLS event on our system? How would a system study tell us how to select an island? This is unclear.
Response: Requirement R1 requires that the Planning Coordinator consider historical events and system studies in selecting island critera but the deliverable for Requirement R1 is a criteria for selecting islands and it doesn't require the entity to have island criteria based on historical events only to consider historical events. The Measure M1 indicates that the entity must have some evidence that it considered historical events.		
The California ISO	No	Cannot support approval until the requirements are closer to being finalized.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Tri-State Generation & Transmission Assoc.	No	Comments: The measures are vague and not performance based leaving much up to interpretation. Measures should contain specific targets or specifications that clarify how an entity will be audited and measured for compliance. These measures merely repeat the requirements and do not provide any useful guidance beyond what is specified in the requirement itself.
Response: The SDT thinks that the Measures identify the evidence or types of evidence needed to demonstrate compliance with the associated requirement. The SDT thinks that the commenter is proposing that the SDT propose the RSAW not the Measures.		
MidAmerican Energy	No	Ensure that measures correctly reflect modified requirement changes. In addition there are concerns with the

Organization	Yes or No	Question 2 Comment
		addition of requirements and measurements to reach concurrence. This potentially subjects an entity to non-compliance based on events beyond that entity's control such as a problematic neighbor that refuses to reach concurrence. This concpept should be removed and replaced with a requirement to distribute the results. Examples include M5 - As noted in the comments below for R5, replace the words "reached concurrence with" with "provided a UFLS design assessment report to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors. M7 - As noted in the comments below for R7, replace "within their Interconnection", with "that have design assessment responsibilities within the islands covered by the UFLS database". Planning Coordinators that are within the same Interconnection, but are not within any islands covered by another Planning Coordinators UFLS database, would not need to receive the UFLS information .M10 - Replace "automatic switching of Facilities" with "automatic switching of Elements" to be consistent with the associated Requirement R10
Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces this with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. **The SDT thinks that database information should be shared beyond that which is being proposed by the commenter. This is the reason why the SDT specified that the PC's share the database with the other PC's within their interconnection. This is a measure to ensure information sharing is happening within the interconnection.** **The SDT made the suggested conforming change to Measure M10.**		
Exelon	No	Exelon does not agree with the concept of allowing neighboring Planning Coordinators to define or modify islanding criteria. There should be a single criteria for the determination of an island which is consistent across the interconnection, unless a specific geographic or regional exception is identified. Even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint.
Response: The SDT is unsure if the commenter is referring to a specific requirement; however, like many other commenters that were concerned with the Planning Coordinators reaching concurrence, the SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators		

Organization	Yes or No	Question 2 Comment
coordinated should an island cross Planning Coordinator areas.		
Progress Energy - Carolinas	No	For M3, it is unclear what is meant by the phrase "including the criteria itself." Since the criteria is specified in R3, we recommend this phrase be deleted from the measure. **Response:The SDT agrees with the commenter and removed the phrase from both M2 and M3.** For M5, this measure should only apply to Planning Coordinators (PCs) who are part of a joint island, but it is written such that it appears to apply to all PCs. We recommend rewording M5 to "Each Planning Coordinator shall have dated evidence...that it reached concurrence with the other affected PCs on design assessment results for any islands in accordance with Requirement R5 and identifies the affected PCs." We also recommend that R5 be reworded to "Each PC shall reach concurrence with all other affected PCs on UFLS design assessment results before design assessment completion for any islands identified by that PC which include a portion of that PC's footprint along with another PCs footprint." **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT also made associated changes to the corresponding measures.**
Ameren	No	In M3, it isn't clear what is meant by "including the criteria itself." The criteria is already specified in Requirement R3, so this phrase does not appear to be needed. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.** M5 should only apply to PCs who would be part of a particular joint island. The present wording seems to suggest that M5 and Requirement R5 would apply to every PC. The wording for M5, and corresponding Requirement R5, should be modified to apply only to the PC's which would be involved with a particular island. **Response: The SDT made conforming changes to Requirement R5 to clarify the coordination between Planning Coordinators.**
Duke Energy	No	M3 - it is unclear what is meant by the phrase "including the criteria itself". Suggest deleting the phrase. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.** Also, requirements R5 and R13 (and hence their Measures and VSLs) are problematic, since they require that Planning Coordinators shall "reach concurrence" with all other affected Planning Coordinators, which may

Organization	Yes or No	Question 2 Comment
		not always be possible. The requirements need to provide for that situation. **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.**
Entergy Services	No	M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that the phrase be deleted. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.** M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. Recommend that the wording in M5 be changed to: "Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified islands in accordance with Requirement R5 and identifies the affected Planning Coordinators." Recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint." **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT made conforming changes to the associated Measures.**
SERC Planning Standards Subcommittee	No	
Response:		
SERC SC UFLS Standard Drafting Team	No	M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that it be deleted. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.** M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. Recommend that the wording in M5 be changed to: "Each Planning

Organization	Yes or No	Question 2 Comment
		Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified islands in accordance with Requirement R5 and identifies the affected Planning Coordinators." Recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint." **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT made conforming changes to the associated Measures.**
Southern Company Transmission	No	M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that it be deleted. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.** M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. Recommend that the wording in M5 be changed to: "Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified islands in accordance with Requirement R5 and identifies the affected Planning Coordinators." Recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint." **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT made conforming changes to the associated Measures.**
American Transmission Co.	No	M5 - As noted in the comments below for R5, replace the words "reached concurrence with" with "provided a UFLS design assessment report to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning

Organization	Yes or No	Question 2 Comment
		Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors. **Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT made conforming changes to the associated Measures.** M7 - As noted in the comments below for R7, replace "within their Interconnection", with "that have design assessment responsibilities within the islands covered by the UFLS database". Planning Coordinators that are within the same Interconnection, but are not within any islands covered by another Planning Coordinators UFLS database, would not need to receive the UFLS information. **Response: The SDT thinks that database information should be shared beyond that which is being proposed by the commenter. This is the reason why the SDT specified that the PC's share the database with the other PC's within their interconnection. This is a measure to ensure information sharing is happening within the interconnection.** M10 - Replace "automatic switching of Facilities" with "automatic switching of Elements" to be consistent with the associated Requirement R10. **Response: The SDT clarified Requirement R10 and Measure M10 by explicitly stating the types of Elements.**
Bonneville Power Administration	No	Measures are too vague, lacking specifics, and not performance-based. This would leave too much up to the Auditor's interpretation. Measures are only valuable if they contain specific targets or specifications that clarify how an entity will be deemed to be compliant with the standard as written. Measures which merely repeat the standard with the inclusion of "shall have evidence such as..." are not very useful. Measures should be explicit, detailed, consistent, and provide useful guidance to entities. These measures do not provide any useful guidance beyond what is specified in the requirement itself.
Response: The SDT thinks that the Measures identify the evidence or types of evidence needed to demonstrate compliance with the associated requirement. The SDT thinks that the commenter is proposing that the SDT propose the RSAW not the Measures.		
FirstEnergy	No	Since we do not agree with some of the standard requirements, we therefore do not agree with the measures for some of the requirements as written.

Organization	Yes or No	Question 2 Comment
Response: The SDT has made conforming changes to the proposed standard that addresses many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Manitoba Hydro	No	Suggest that the measures be modified to reflect any changes made to standards Requirements per the comments made to questions Q4 through Q13. **Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.** M10 - Replace “automatic switching of Facilities” with “automatic switching of Elements” to be consistent with the associated Requirement R10. **Response: The SDT clarified Requirement R10 and Measure M10 by explicitly stating the types of Elements.**
MRO’s NERC Standards Review Subcommittee (NSRS)	No	Suggest that the measures be modified to reflect any changes made to standards Requirements per the comments made to questions Q4 through Q13. **Response: The SDT has made conforming changes to the proposed standard that addresses many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.** M10 - Replace “automatic switching of Facilities” with “automatic switching of Elements” to be consistent with the associated Requirement R10. **Response: The SDT clarified Requirement R10 and Measure M10 by explicitly stating the types of Elements.**
IESO	No	The measures that refer to Requirements with subrequirements (e.g. R2, R3, and R4) should be more consistent. **Response: The SDT thinks that the Measures as written accurately refer to the associated Requirement sub-parts.** All of the corresponding Measures (e.g. M2 and M4) should include the final phrase: “including the criteria itself” or none should include this phrase. **Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3.**

Organization	Yes or No	Question 2 Comment
Tennessee Valley Authority (TVA)	No	TVA believes the following changes to the Measures should be considered:M3: It is unclear what action is intended by the phrase “including the criteria itself.” Since the criteria are specified in R3, it is recommended that it be deleted.
Response: The SDT agrees with the commenter and removed the phrase from both M2 and M3		
Southern California Edison Company	No	We do not agree with the proposed reliability standard and, therefore, we cannot agree with the proposed Measures.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Pepco Holdings, Inc. - Affiliates	No	We do not concur with the requirements as written
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
SPP System Protection and Control Working Group	No	What is meant by “criteria” in Requirement R1? Does “criteria” in R1 have to be justified?
Response: The criteria in Requirement R1 is the criteria used to select islands as the basis for the UFLS program design.		
Indiana Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
Long Island Power Authority	Yes	
MEAG Power	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	

Organization	Yes or No	Question 2 Comment
ReliabilityFirst Engineering Staff	Yes	
South Carolina Electric and Gas	Yes	
Springfield Utility Board	Yes	
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
Illinois Municipal Electric Agency	Yes	For M8, M9, and M10 applicable to UFLS entity/TO.
Response: Thank you for your support.		
Northeast Power Coordinating Council	Yes	The Measures are logical and consistent with the corresponding requirements.
Response: Thank you for your support.		
Wisconsin Electric Power Company (dba We Energies)	Yes	We agree with the Measures as far as the draft standard is currently written, however, see our comments for questions 11, 12, and 13 that would require modifications to requirements R9 & R10 and to M9 & M10.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		

3. The SDT drafted Violation Severity Levels for the requirements. Do you agree with the proposed Violation Severity Levels?

Summary Consideration:

Some comments received indicated that the increments in the VSLs were arbitrary. The standard drafting team used the NERC and FERC VSL guidelines to develop the proposed VSLs. However, several commenters suggested making changes to the VSLs such as VSL for Requirement R11 and the team made conforming changes.

The team changed the phrase, “Planning Coordinator footprint” with the phrase, “Planning Coordinator area” throughout the standard.

Organization	Yes or No	Question 3 Comment
Xcel Energy		No comments
The California ISO	No	Cannot support approval until the requirements are closer to being finalized.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Tri-State Generation & Transmission Assoc.	No	Comments: We believe that individual Planning Coordinators are not the appropriate entities to be responsible for determining criteria for areas that may form islands, for identifying the islands, for developing the UFLS program, for periodic assessments, for maintaining databases, or for assessing events. Further, Planning Coordinator footprints are neither defined nor is there any guidance on how they should be established. **Response: The definition of the Planning Coordinator according to the Function Model Version 5 states: The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.** Every VSL that refers to a PC footprint should be clarified. **Response: The SDT replaced “footprint” with “area” to be consistent with the Functional Model.** What is meant by “annually maintain” is neither clear nor defined. **Response: The SDT modified Requirement R7 to clarify the intent of the UFLS database: Each Planning Coordinator shall annually maintain a UFLS database containing *data necessary to model its***

Organization	Yes or No	Question 3 Comment
		UFLS program for use in event analyses and assessments **of the UFLS program.** The VSL for R6 should be re-written.The increment size between VSLs seems arbitrarily small in R9 and R10. Is there a reliability basis for choosing 5%? **Response: The SDT established increments in the VSLs according to the VSL NERC guidelines.**
Bonneville Power Administration	No	Criteria are never actually defined in the requirements. **Response: The criteria in Requirement R1 is the criteria used to select islands as the basis for the UFLS program design.** Planning Coordinator footprints are not established. **Response: The SDT replaced "footprint" with "area" to be consistent with the Functional Model.** **The definition of the Planning Coordinator according to the Function Model Version 5 states: The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.** What does "annually maintain" mean? Does it mean the Database requires annual updates, annual reviews or just to provide a database annually? Frequency excursions precede an islanding event. I.e. low frequency initiates UFLS which should prevent an unintentional islanding event. The wording of this requirement makes it seem like the islanding event occurs first and causes the UF. **Response: The SDT modified Requirement R7 to clarify the intent of the UFLS database: Each Planning Coordinator shall annually maintain a UFLS database containing** ***data necessary to model its UFLS program for use in event analyses and assessments*** **of the UFLS program.**
MEAG Power	No	Developing a VSL tool similar to the VRF tool would be beneficial. The VSL seem arbitrary. For example, R1 has a "moderate" and "high" VSL if you do not take into account historical events when documenting and developing the criteria, but what if your sub-region never had an UF event? You are still in compliance?
Response: The SDT established the VSLs according to the VSL NERC guidelines. Requirement R1 requires that a Planning Coordinator consider historical events in establishing island criteria and does not require that they select islands based on historical islands that have formed.		
SPP System Protection and Control Working Group	No	For R11, the lower VSL is stated as a requirement and not as a VSL. Does it need to be reworded?

Organization	Yes or No	Question 3 Comment
Response: The SDT made conforming changes to the VSL for Requirement R11.		
Progress Energy - Carolinas	No	For R4, the VSLs should include a consideration of the timeliness of the completion of the required study (e.g. lower VSL for 3 months late, Moderate for 3-6 months late, etc.). **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary.** For the R11 VSLs, we recommend that the time ranges for the VSLs be expanded to allow more than one month between Low, Moderate, High and Severe. We would suggest revising to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months past the 12 month requirement. **Response: The SDT does not agree with the recommendation to add a range of time to the VSLs. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
Ameren	No	For Requirement R11, the 'Lower' VSL needs rewording. This VSL as written is just a repeat of the requirement text. Also, the time ranges for the VSL's should be expanded. Suggested ranges: Moderate: 12-14 months; High: 14-16 months; Severe: 16-18 months.
Response: The SDT made conforming changes to the VSL for Requirement R11. The SDT does not agree with the recommendation to add a range of time to the VSLs. The SDT established increments in the VSLs according to the VSL NERC guidelines.		
AECI	No	In R1 it is unclear how to use historical events and system studies to select portions of the BES. **Response: Requirement R1 requires that the Planning Coordinator consider historical events and system studies in selecting island criteria but the deliverable for Requirement R1 is a criteria for selecting islands and it doesn't require the entity to have island criteria based on historical events only to consider historical events.** In R4, I can see how we should be responsible for our own generators, but the information for generation owned by others is only as good as the data we receive. **Response: The SDT clarified in the Effective Date section of the standard that Requirement R4 is not effective until PRC-024 is approved and effective.** In R7 for the lower VSL, up to 40 days seems like it would include 30, should it be changed to say between 30 and 40? **Response: The SDT agrees with the commenter and made conforming changes to the VSL.**

Organization	Yes or No	Question 3 Comment
		In R11, for the lower VSL, it appears to be just a restatement of the requirement rather than a VSL. **Response: The SDT made conforming changes to the VSL for Requirement R11.**
MRO's NERC Standards Review Subcommittee (NSRS)	No	Most of the VSLs are okay. However, the VSLs for R5 and R13 depend on reaching "concurrence" with other entities, which is not a valid basis for measuring compliance. If the concurrence requirement is not revised as suggested below, then we propose that the VSL levels be reduced.
Response: The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.		
Western Electricity Coordinating Council	No	R1 unclear definition of "criteria" it is never actually defined in the requirement. **Response: Requirement R1 requires that the Planning Coordinator consider historical events and system studies in selecting island criteria but the deliverable for Requirement R1 is criteria for selecting islands and it doesn't require the entity to have island criteria based on historical events only to consider historical events.** R2 For clarity Severe level should use the term "greater than 2" of the parts instead of "all" of the parts **Response: The SDT thinks that the intent is the same and did not make any conforming changes to the VSL for Requirement R2.** R3 For clarity Severe level should use the term "greater than 2" of the parts instead of "all" of the parts **Response: The SDT thinks that the intent is the same and did not make any conforming changes to the VSL for Requirement R2.** R4 no comment OKR5 very difficult to apply since Planning Coordinator footprints are not established. VSL could be based on number of adjacent PC's that do not concur. **Response: The SDT replaced "footprint" with "area" to be consistent with the Functional Model.** **The definition of the Planning Coordinator according to the Function Model version 5 states: The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.** **The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the**

Organization	Yes or No	Question 3 Comment
		Planning Coordinators coordinated should an island cross Planning Coordinator areas. R6 Not clear on what "annually maintain" means. Does it mean the Database requires annual updates, annual reviews or just the ability to provide a database annually? **The SDT modified Requirement R7 to clarify the intent of the UFLS database: Each Planning Coordinator shall annually maintain a UFLS database containing *data necessary to model its UFLS program for use in event analyses and assessments* of the UFLS program. Note that the team also revised Requirement R6 to provide greater clarity on the use of the word, 'annually.'** R7 at least some of the severity level should be based on the number of requests that were late rather than the time the request was overdue particularly since only an "annual maintenance" is required there is no difference in reliability impact if delivery is made in 30 or 60 days. **Response: FERC VSL guideline 4 (G4) states that a Violation Severity Level Assignment should be based on a single violation, not on a cumulative number of violations. Adopting the commenter's suggestion would violate this guideline.** R8 at least some severity level should be dependent on the lack of sufficiency of data as opposed to the amount of time it was overdue. **Response: FERC VSL guideline 4 (G4) states that a Violation Severity Level Assignment should be based on a single violation, not on a cumulative number of violations. Adopting the commenter's suggestion would violate this guideline.** R9 No comments I will assume the percentages have some basis and are not just arbitrary.R10 No comments I will assume the percentages have some basis and are not just arbitrary. **Response: Thank you for your comments.** R11 With respect to the VSLs I would recommend not combining the time duration and inclusion of parts. Use timing for lower and moderate and the lack of components for High and Severe. I have to be dumb here with the wording of the requirement. Does not the frequency excursion precede the islanding event. i.e. low frequency initiates UFLS which should prevent an unintentional islanding event. The wording of this requirement makes it seem like the islanding event occurs first and causes the UF This Requirement and VSL places emphasis on performing analysis and does not address any possible violation for actually having an inadequate UFLS program resulting in unintended islanding. **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary.** R12 VSL should be binary. Severe for failure to perform the assessment in the required time. Actually the

Organization	Yes or No	Question 3 Comment
		Requirement should be to "implement" the changes and correct the deficiencies not just to "consider" them in another assessment. If implementation were the focus the VSL's could be based on amount of implementation completed within a specified time frame. **Response: The SDT does not agree that the VSL for Requirement R12 should be a binary. The SDT thinks that the program is required to meet performance characteristics in Requirement R4. Requirement R12 requires that the Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. The timeliness of the assessment is an important element of the requirement and should be reflected in the VSLs.** R13 See comments for R5 with respect to PC footprint and also there is no clear indication of what is meant by event affecting other PC's does this mean islanding in the other areas or UF load shed or equipment switching? **Response: The SDT replaced "footprint" with "area" to be consistent with the Functional Model.** **The definition of the Planning Coordinator according to the Function Model version 5 states: The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.**
Y-W Electric Association, Inc.	No	Regarding the VSLs for R8, the UFLS entities cannot be punished for failing to meet a schedule if the schedule is not mutually agreed upon between the Planning Coordinator and the UFLS entities to ensure that the UFLS entities are capable of meeting such a schedule. At the very least, there must be some protection for the UFLS entities provided that requires the Planning Coordinator(s) to give the UFLS entities long-term notice of the deadlines that they will need to meet. The lack of any scheduling restrictions for the Planning Coordinators in the standard as written has a strong potential to cause enormous burdens on small UFLS entities that simply do not possess the resources to deal with such data reporting requirements without sufficient advance notice. Additionally, the UFLS entities cannot be penalized for failing to submit data in a format over which they have no control or input. The Planning Coordinator should be required to consult with the UFLS entities and decide upon a mutually agreeable data format in order to ensure that the UFLS entities are capable of providing the required data in the required format. With no language in the standard limiting or clarifying what data can be required of the UFLS entities by the Planning Coordinator, this provision at least should be made to protect small UFLS entities with highly limited resources for dealing with such data reporting requirements.
Response: The SDT added a requirement to the proposed standard, Requirement R14, to ensure that the Planning Coordinators collect and respond to		

Organization	Yes or No	Question 3 Comment
comments submitted by UFLS entities on the UFLS program, including a schedule for implementation and UFLS design assessment.		
Duke Energy	No	See comment to question #2 above.
Response: Please see our response to your comment to question #2.		
FirstEnergy	No	Since we do not agree with some of the standard requirements, we therefore do not agree with some of the VSL for the requirements as written.
Response: The SDT has made conforming changes to the proposed standard that addreses many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
IRC Standards Review Committee	No	The ability for the PC to comply with R1 and R2 requires ULFS entities and Transmission Owners to comply with this standard. The VSLs should clearly state that it is the PC who did not meet its obligations under R1 and R2 and not that non-compliance to R1 and R21 was the result of non-compliance by a third party which the PC relied on into meeting its obligations under this standard.
Response: The SDT is unclear as to how and why the Planning Coordinator needs to rely on the UFLS entities to comply with the requirements assigned to it. The SDT thinks that the Planning Coordinator can meet the obligations assigned to it in the proposed standard.		
Entergy Services	No	The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. **Response: The SDT made conforming changes to the VSL for Requirement R11.** Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented."The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.). **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
SERC Planning Standards Subcommittee	No	The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation.

Organization	Yes or No	Question 3 Comment
		Response: The SDT made conforming changes to the VSL for Requirement R11. Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe 16-18 months. **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
SERC SC UFLS Standard Drafting Team	No	The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. **Response: The SDT made conforming changes to the VSL for Requirement R11.** Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented."The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.). **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
Southern Company Transmission	No	The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. **Response: The SDT made conforming changes to the VSL for Requirement R11.** Recommend that the time ranges for the VSLs addressing being late with the assestment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented."The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.). **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
Tennessee Valley Authority	No	The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a

Organization	Yes or No	Question 3 Comment
(TVA)		violation. **Response: The SDT made conforming changes to the VSL for Requirement R11.** Recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented."The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.). **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The SDT established increments in the VSLs according to the VSL NERC guidelines.**
Southern California Edison Company	No	We do not agree with the proposed reliability standard and, therefore, we cannot agree with the proposed Violation Severity Levels.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
Pepco Holdings, Inc. - Affiliates	No	We do not concur with the requirements as written, so this activity is premature.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		
American Transmission Co.	Yes	
Exelon	Yes	
IESO	Yes	
Indiana Municipal Power Agency	Yes	
Long Island Power Authority	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 3 Comment
MidAmerican Energy	Yes	
Northeast Power Coordinating Council	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst Engineering Staff	Yes	
South Carolina Electric and Gas	Yes	
Springfield Utility Board	Yes	
United Illuminating Company	Yes	
Northeast Utilities	Yes	Although NU agrees with the intent of the subject VSLs, we suggest that for Requirement R8 (Moderate and Severe) that the text beginning with OR is deleted. Additionally we suggest: o For Lower, Moderate and High VSLs - the first sentence be revised to read “The UFLS Entity provided data, in the format specified, to its Planning ...” o For Severe VSL - the first sentence be revised to read “The UFLS Entity failed to provide data, in the format specified, to its Planning Coordinator(s) within 20 calendar days ...”
Response: The SDT appreciates the formatting suggestions made by the commenter. The SDT thinks that they have accurately reflected the content of the Requirements in the associated VSLs.		
Wisconsin Electric Power Company (dba We Energies)	Yes	We agree with the Violation Severity Levels as far as the draft standard is currently written, however, see our comments for questions 11, 12, and 13 that would require modifications to requirements R9 & R10 and the corresponding Violation Severity Levels.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.		

4. In the second posting, many of the requirements were assigned to groups of Planning Coordinators. These groups were to consist of all the Planning Coordinators within each of the Regional Entity footprints. The SDT has now revised these assignments to replace the groups with individual Planning Coordinators due to difficulties involved in assigning responsibilities to groups that do not currently exist. Do you agree with this revision?

Summary Consideration:

Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model version 5.

Commenters expressed confusion over having Transmission Owners as part of UFLS Entities but separated out as Transmission Owners in Requirement R10.The team reviewed the rationale for this structure and suggested merging Requirements R9 and R10. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements.

Organization	Yes or No	Question 4 Comment
GDS Associates	No	- Standard not entirely clear regarding to whom will apply (see 4.), groups or individual Planning Coordinators within the Regional Entity footprint.- Not sure what is the intent for paragraph 4.3
Response: The standard applies to individual Planning Coordinators, not groups. Applicability 4.3 is intended for Transmission Owners that may need to switch equipment other than load, such as shunt compensation to control over voltage.		
Wisconsin Electric Power Company (dba We Energies)	No	Although we agree that the Planning Coordinator has the wide-area view and technical skills to oversee the design of and ensure the effectiveness of a UFLS program, we are concerned with how this concept will actually play out, especially when a UFLS Entity is within multiple Planning Coordinators' footprints.
Response: In the case of a UFLS Entity in multiple Planning Coordinator footprints, that entity may need to set UFLS relays differently and may need to accommodate different schedules in the different footprints.		

Organization	Yes or No	Question 4 Comment
Tri-State Generation & Transmission Assoc.	No	Comments: Individual Planning Coordinators are not the entities to determine how islands should be formed, unless the Regional Assurer is required to become the only remaining Planning Coordinators, which would be acceptable. The current registration by numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. All Planning Coordinators within an interconnection should be required to collaboratively develop an Interconnection Coordinated UFLS Plan. UFLS works on interconnection basis not on PC footprint basis. We believe that the Regional Assurer will be better able to manage UFLS programs to the extent that the standard clearly lays out what must be accomplished. The primary purpose of any UFLS program is to mitigate the need to form islands by balancing total system loads and resources. It is only a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding events rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts within the interconnection. Again, we believe that the Regional Assurer will be better able to manage UFLS programs to the extent that the standard clearly lays out what must be accomplished We strongly believe that this should remain the responsibility of the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate or address the interconnection reliability needs.

Response: The SDT believes the Planning Coordinator, having a wide-area view and the necessary technical skills, is the proper entity to oversee the design and implementation of UFLS. There is also wide industry support for the Planning Coordinator as the proper entity for UFLS. The Reliability Assurer has a very limited scope of activity in the Functional Model and is not a user, owner or operator of the BES. The SDT recognizes the need to at least preserve coordination on the regional level and has inserted a requirement (Requirement R2, Part 2.3) to identify each Regional Entity footprint as an island to be assessed for UFLS performance. The PC's within each region will need to work with each other in order to produce a successful assessment.

The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.

Organization	Yes or No	Question 4 Comment
Exelon	No	Exelon does not agree with the concept of allowing neighboring Planning Coordinators to define or modify islanding criteria. There should be a single criteria for the determination of an island which is consistent across the interconnection, unless a specific geographic or regional exception is identified. Even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint.
Response: Neighboring Planning Coordinators cannot redefine or modify another Planning Coordinator's R1 island determination criteria. A Planning Coordinator may, however, select an island that overlaps a neighboring Planning Coordinator's footprint in complying with R2. A single criterion for island determination is not something that can be put into a continent-wide standard because many approaches to these criteria are likley to be acceptable.		
Bonneville Power Administration	No	It doesn't make sense to assign responsibilities to organizations that are not currently formed. Footprint or jurisdiction of Planning Coordinators has not been established and no mechanism exists for assigning a specific UFLS entity into a PC's jurisdiction. PCs within an interconnection should be required to develop an Interconnection Coordinated UFLS Plan. UFLS works on interconnection basis not on PC footprint basis. The purpose of the UFLS Plan is to mitigate the need to form islands by balancing loads and resources; a secondary function would be to balance the loads and resources after the islands have been formed. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts within the interconnection.
Response: The SDT agrees that responsibilities should not be assigned to organizations that are not currently formed. The SDT disagrees that the jurisdiction of Planning Coordinators and their footprints has not been established. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. **The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.**		
AECI	No	It is unclear what is meant by footprint if it is not a regional entity footprint. For those of us on a heavily interconnected border between two regional entities, do we now share a footprint with them? What about other utility's loads on our system, or vice versa, would we share a footprint with them as well? Also, R2.3 talks about if you are in multiple footprints, each of those footprints shall be identified as an island. Does that mean each footprint is a separate island or each footprint is included in the same big island?
Response: Planning Coordinators have footprints also. It is possible that a Distribution Provider or Transmission Owner can own equipment in two or		

Organization	Yes or No	Question 4 Comment
more Planning Coordinator footprints. If a utility is also a Planning Coordinator and has loads of another utility, also a Planning Coordinator, interspersed within its footprint, it may be best for both to un-register as Planning Coordinators and have a higher level entity register instead. **Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. There are no requirements to identify Planning Coordinator footprints as islands. The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs because Planning Coordinators within each Regional Entity footprint will need to coordinate with each other in order to produce successful UFLS design assessment for each regional island.**		
Entergy Services	No	R5 and R13 seem very problematic. The standard requires that both or all the entities agree. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two companies cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. R13 is not covered by R11 and cannot be eliminated; R13 is to R11 as R5 is to R4.		
SERC SC UFLS Standard Drafting Team	No	R5 and R13 seem very problematic. The standard requires that both or all the entities agree. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two companies cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among		

Organization	Yes or No	Question 4 Comment
Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. R13 is not covered by R11 and cannot be eliminated; R13 is to R11 as R5 is to R4.		
Southern Company Transmission	No	R5 and R13 seem very problematic. The standard requires that both or all the entities agree. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two companies cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. R13 is not covered by R11 and cannot be eliminated; R13 is to R11 as R5 is to R4.		
Ameren	No	Requirement R1 should be revised to read "Each Planning Coordinator, in coordination with its constituent Transmission Owners and Transmission Planners, shall develop and document criteria...". Further, it should include that the Regionla Entity should be involved in the studies, as in many cases, the RE has performed or were involved in thses studies. similarly, Requirement R2 should be revised to read "Each Planning Coordinator, in coordination with its constituent Transmission Owners and Transmission Planners, shall identify one or more islands...". Requirement R3 should be revised to read "Each Planning Coordinator, in coordination with its constituent Transmission Owners, Distribution Provider and Transmission Planners, shall develop a UFLS program..." The Planning Coordinator should in all UFLS related activities include UFLS plans and procedures which their Transmission Owner, Distribution Provider and Transmission Planners may have had in place, and functioning adequately, perhaps for many years.
Response: The SDT agrees that Transmission Owners and Transmission Planners should be involved in R1, R2 and in R3 along with Distribution Providers, but for compliance purposes, requirements must be clearly assigned to one specific entity. Adding the suggested phrase will cause confusion as to who is responsible to do what. The Functional Model description of Planning Coordinator includes coordination with other entities; the UFLS function should be expected to be added to the Planning Coordinator function once this standard is approved. Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES.		

Organization	Yes or No	Question 4 Comment
Progress Energy - Carolinas	No	Requirements R5 and R13 require Planning Coordinators (PCs) from two or more areas to agree on assessment results. However, no process is provided in the event that the PCs cannot agree. One party may have larger margin requirements or a different methodology and these differences may not be reconcilable. Therefore, it is possible that multiple PCs could be prevented from meeting the agreement requirement through no fault of their own. There needs to be a process for resolving this. We recommend that R5 include "If concurrence cannot be reached, an individual PC in the applicable island may demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply that PC's individual scheme to the entire island." Also, we recommend that R13 be deleted since R11 would effectively require these actions for multi-PC islands.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. R13 is not covered by R11 and cannot be eliminated; R13 is to R11 as R5 is to R4.		
Southern California Edison Company	No	SCE does not agree with this revision and supports WECC's position that "The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators."
Response: The SDT shares SCE's concern regarding further fragmentation of UFLS plans. The standard requires the identification of Regional Entity footprints as islands to be used in UFLS design assessments (Requirement R2, Part 2.3) and that the Planning Coordinators within each Regional Entity footprint work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within an interconnnection. The SDT believes that a continent-wide standard cannot require single UFLS plans for each interconnection. The degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; flexibility needs to be reserved to address regional needs. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design.		
Western Electricity Coordinating Council	No	The PCs within an interconnection should be required to coordinate a UFLS Design with all other PCs within the Interconnection and the PCs should be required to develop an Interconnection Coordinated UFLS Plan. UFLS works on interconnection basis not on PC footprint basis. The primary purpose of the UFLS Plan is designed to mitigate the need to form islands by balancing loads and resources. It is a secondary function to balance the loads and resources after the islands have been formed. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts

Organization	Yes or No	Question 4 Comment
		within the interconnection.From an audit and enforcement standpoint, no mechanism exists for assigning a specific UFLS entity into a PC's jurisdiction. This has the potential for making this standard unauditable for any entity which is not designated by a PC unless some guidance is established to determine a PC's footprint.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard requires the identification of Regional Entity footprints as islands to be used in UFLS design assessments (Requirement R2, Part 2.3) and that the Planning Coordinators within each Regional Entity footprint work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within an interconnnection. The SDT believes that a continent-wide standard cannot require single UFLS plans for each interconnection. **The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.** **The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design.** **The SDT disagrees that the jurisdiction of Planning Coordinators and their footprints has not been established. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities.**		
Xcel Energy	No	The problem still exits that the mapping of Planning Coordinators to 'subordinate' entities is not clear. Creating additional requirements for a functional entity that is still nebulous creates more confusion.We also believe the term "island" should be a defined NERC term. It is used throughout the standard with the meaning being generally understood within the industry but not explicitly stated.
Response: The SDT disagrees that mapping of Planning Coordinator footprints to UFLS Entities is not clear. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. **The SDT believes the term "island" to be readily understood and does not see a benefit of defining it in the NERC glossary even though its meaning in the industry is not the same as the dictionary definition.**		
Pepco Holdings, Inc. - Affiliates	No	The SDT has essentially defined groups by requiring concurrence.
Response: The SDT abandoned the group of Planning Coordinators concept because of compliance issues as stated in the background section. Concurrence was another method of gaining coordination among individual Planning Coordinators. (Note that the SDT has modified R5 and R13 to address concerns of other commenters on concurrence.) Without some level of cooperation among Planning Coordinators, further fragmentation of UFLS plans, which have been coordinated on a regional basis in the past, is likely. The SDT does not believe further fragmentation is in the interest of		

Organization	Yes or No	Question 4 Comment
reliability.		
American Transmission Co.	Yes	
FirstEnergy	Yes	
IESO	Yes	
Illinois Municipal Electric Agency	Yes	
Indiana Municipal Power Agency	Yes	
Long Island Power Authority	Yes	
Manitoba Hydro	Yes	
MEAG Power	Yes	
MidAmerican Energy	Yes	
Northeast Power Coordinating Council	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC Planning Standards Subcommittee	Yes	

Organization	Yes or No	Question 4 Comment
South Carolina Electric and Gas	Yes	
SPP System Protection and Control Working Group	Yes	
Tennessee Valley Authority (TVA)	Yes	
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
MRO's NERC Standards Review Subcommittee (NSRS)	Yes	Although THE NSRS agrees with changing the applicability of the requirements from groups of Planning Coordinators to each Planning Coordinator, the present wording in R2.3 says that for a PC with a part of its footprint in more than one region, "each of those Regional Entity footprints shall be identified as an island." We propose that the wording be revised to require a PC with part of its footprint in more than one region to identify only those appropriate parts of its area that are in islands, not the entire Registered Entity footprint where it may be present.
Response: The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. To this end, Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. These islands are to be used in UFLS design assessments and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. There are no requirements to identify Planning Coordinator footprints as islands, but all of a Coordinator's area will be included in one island or another.		
NERC Staff	Yes	NERC staff understands and supports this change to replace the groups with individual Planning Coordinators and agrees that it is a good hybrid approach. While NERC recognizes that the move might not be the ideal way to coordinate interregionally, at this point it does seem to be the best way to assign these requirements.
Response: Thank you for your support.		
Springfield Utility Board	Yes	There remains some abiguity with regards to the following language:"UFLS entities shall mean all entities that are responsible for the ownership,operation, or control of UFLS equipment as required by the UFLS programestablished by the Planning Coordinators. Such entities may include one or moreof the following:4.2.1 Transmission Owners4.2.2 Distribution Providers"SUB is fine with the Planning Coordinator

Organization	Yes or No	Question 4 Comment
		having the authority to determine UFLS requirements and affected entities. But there is a problem with regards implementation of a Planning Coordinator decides that equipment is required where it was not previously required by an entity. What is the process for the Planning Coordinator to provide notice to a registered entity (such as a Distribution Provider)? If a UFLS is required of a DP where a UFLS did not previously exist, what is the implementation plan for becoming compliant without having to be out of compliance on Day 1 just becuase a PC sent a letter?Under the implementation plan where it states:"The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time to develop or modify UFLS programs and to establish a schedule for implementation." Is this language intended for the PC to establish a schedule for implimentation of affected entities that fall under the standard after the standard is adopted?
Response: The SDT agrees that UFLS Entities should have opportunity to provide input to the Planning Coordinator on what will be required of them. R14 has now been added to the standard and requires a peer review of a Planning Coordinator's design and schedule for implementation by the UFLS Entities. **The Planning Coordinator has one year to come up with a design and schedule for implementation, but the UFLS Entities are subject only to the Coordinator's schedule according to R9, not this one year phase-in.**		
IRC Standards Review Committee	Yes	We agree; however, this standard should not disallow the ability for some PCs to group together to develop a wide area UFLS plan. To the extent some PCs do this, the standard should be written and performance measured in a manner that does not cause these PCs to duplicate the same documents that may already be provided by another PC for the same footprint.
Response: Each individual Planning Coordinator is subject to compliance. The group concept was abandoned to avoid complaince issues as mentioned in the background section. The standard does not disallow voluntary groupings of Planning Coordinators, but each Planning Coordinator would still be responsible for its own compliance.		
Duke Energy	Yes	Yes, except for the issue on "reaching concurrence" identified in our response to question #2 above (R5 and R13).
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern.		

5. Several commenters indicated in the second posting potential conflicts and redundancies between PRC-006-1 and EOP-003-1 requirements. The SDT agrees that EOP-003-1 contains requirements that are redundant and/or conflict with the proposed requirements in PRC-006-1. The SDT sought approval to post a supplemental SAR to include EOP-003-1 Underfrequency Load Shedding related requirements in the scope of the UFLS SDT. The SC agreed to post the SAR with a proposal to revise the original scope of the UFLS SAR and the SDT revised the EOP-003-1 requirements to remove the conflicts.

Summary Consideration:

While the standard drafting team received support for the changes to EOP-003 eliminating the redundancy between it and PRC-006 related to underfrequency load shedding requirements, some commenters indicated that the standard drafting team should clarify that the remaining requirements in EOP-003 are related to automatic undervoltage load shedding and manual under frequency load shedding. The drafting team made a conforming change to the proposed standard to clarify that the requirements exclude automatic underfrequency load shedding by adding the following phrase to Requirements R3 and R5: excluding under-frequency load shedding plans

Other comments received indicated that the standard drafting team should revise the requirements related to undervoltage load shedding; however, there is a NERC project tasked with revising EOP-003 and while it is at the initial stages this team will address the requirements that require revision. In addition, the Supplemental SAR approved by the Standards Committee limits the scope to removing conflicts and redundancies related to under-frequency load shedding only in EOP-003-1.

Organization	Yes or No	Question 5 Comment
Xcel Energy		No comments
ReliabilityFirst Engineering Staff		No response seems applicable.
MidAmerican Energy	No	The SAR needs to recognize that all the standards are interconnected and other existing standards development. Automatic load shedding needs to be left in PRC-006. Manual load shedding should be left in EOP-003 according to already existing standards proposed changes. The SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and referring them to a new UVLS standard or PRC-006.
Response: The Supplemental SAR approved by the Standards Committee limits the scope to removing conflicts and redundancies related to under-frequency load shedding only in EOP-003-1.		

Organization	Yes or No	Question 5 Comment
Ameren	Yes	
American Transmission Co.	Yes	
Duke Energy	Yes	
Exelon	Yes	
IESO	Yes	
IRC Standards Review Committee	Yes	
Long Island Power Authority	Yes	
MEAG Power	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Progress Energy - Carolinas	Yes	
South Carolina Electric and Gas	Yes	
Southern California Edison Company	Yes	
SPP System Protection and Control Working Group	Yes	
Springfield Utility Board	Yes	
Tennessee Valley Authority	Yes	

Organization	Yes or No	Question 5 Comment
(TVA)		
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
Indiana Municipal Power Agency	Yes	IMPA agrees with these actions.
Wisconsin Electric Power Company (dba We Energies)	Yes	See comments for question 6 and 7.
Western Electricity Coordinating Council	Yes	This really doesn't look like a question, and it appears the actual question is asked in number 6.
FirstEnergy	Yes	While we agree with the inclusion of the EOP-003 in this project, the versioning and requirement language adjustments requires coordination with the proposed revision of EOP-003 that is taking place with the Order 693 Directives work Project 2010-12.
Response: The scope of work addressed under the Order 693 Directives was revised so that Project 2010-12 no longer addresses EOP-003.		

6. Do you agree with the expanded scope in the Supplemental SAR?

Summary Consideration:

While the standard drafting team received support for the changes to EOP-003 eliminating the redundancy between it and PRC-006 related to underfrequency load shedding requirements, some commenters indicated that the standard drafting team should clarify that the remaining requirements in EOP-003 are related to automatic undervoltage load shedding and manual under frequency load shedding. The drafting team made a conforming change to the proposed standard to clarify that the requirements exclude automatic underfrequency load shedding.

Other comments received indicated that the standard drafting team should revise the requirements related to undervoltage load shedding; however, there is a NERC project tasked with revising EOP-003 and while it is at the initial stages this team will address the requirements that require revision.

Organization	Yes or No	Question 6 Comment
Xcel Energy		No comments
IRC Standards Review Committee	No	Please see comments to 7.
MidAmerican Energy	No	The SAR needs to recognize that all the standards are interconnected and other existing standards development. Automatic load shedding needs to be left in PRC-006. Manual load shedding should be left in EOP-003 according to already existing standards proposed changes. The SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and referring them to either a new UVLS standard or PRC-006
Response: There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
American Transmission Co.	No	We propose that the scope of the SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for also removing the automatic UVLS requirements from EOP-003-1 and referring them to a new PRC standard.
Response: There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	No	We propose that the scope of the SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and moving them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and moving them to a new PRC standard
Response: There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	We propose that the scope of the SAR be revised to call for removing all of the automatic UFLS requirements from EOP-003-1 and moving them to PRC-006-1 standard because no automatic load shedding system requirements should be in the EOP standards. We also note that a separate SAR should be initiated to call for the removal of all the automatic UVLS requirements from EOP-003-1 and moving them to a new PRC standard for the same reason.
Response: There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
Ameren	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Entergy Services	Yes	
Exelon	Yes	
IESO	Yes	
Indiana Municipal Power Agency	Yes	
Long Island Power Authority	Yes	
MEAG Power	Yes	

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Progress Energy - Carolinas	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC Planning Standards Subcommittee	Yes	
SERC SC UFLS Standard Drafting Team	Yes	
South Carolina Electric and Gas	Yes	
Southern Company Transmission	Yes	
SPP System Protection and Control Working Group	Yes	
Tri-State Generation & Transmission Assoc.	Yes	
United Illuminating Company	Yes	
Western Electricity Coordinating Council	Yes	

Organization	Yes or No	Question 6 Comment
Y-W Electric Association, Inc.	Yes	
NERC Staff	Yes	NERC staff agrees that it is wise to revise requirements specific to Underfrequency Load Shedding in EOP-003-1 to remove inconsistencies and redundancies. The only concern is that because both ad hoc team for expediting certain standards processes and the original EOP-003-1 SDT are working on modifications to the standard, there could be some overlap and miscommunication, especially with respect to these redundancies between PRC-006-1 and EOP-003-1.
Response:The Order 693 Directives team has removed revisions to EOP-003-1 from the scope of its project.		
Tennessee Valley Authority (TVA)	Yes	TVA supports this direction to remove the automatic load shedding components (UFLS and UVLS) from EOP-003 to avoid potential conflict with the PRC standards that address UFLS and UVLS.
Response: Thank you for your supportive comment.		
Southern California Edison Company	Yes	We agree in principle with the expanded scope for the Supplemental SAR.
Response: Thank you for your supportive comment.		
Wisconsin Electric Power Company (dba We Energies)	Yes	We agree with the expanded scope of the supplemental SAR, however, EOP-003-1 needs further revision to focus this standard solely on manual loadshed. References to the development of both UFLS and UVLS programs need to be removed from EOP-003-1 as PRC-006-1 will cover automatic UFLS programs and a series of other PRC standards already cover automatic UVLS programs. The SDT should delete R2, R4, R7 and M1 from the posted SDT revised draft standard EOP-003-1 as part of supplemental SAR limited scope of revising requirements related to underfrequency loadshedding. In addition, the SDT should give consideration to inserting the word “manual” in front of the words “load shedding” in R3 and R5 in the posted SDT revised draft standard EOP-003-1. The Measures and Violation Severity Level sections would need to be updated accordingly.
Response: The drafting team made a conforming change to the proposed EOP-003-1 standard to clarify that the requirements exclude automatic underfrequency load shedding. Removing references to UVLS from EOP-003-1 goes beyond the scope of the supplemental SAR.		
FirstEnergy	Yes	While we agree with the inclusion of the EOP-003 in this project, the versioning and requirement language adjustments requires coordination with the proposed revision of EOP-003 that is taking place with the Order

Organization	Yes or No	Question 6 Comment
		693 Directives work Project 2010-12.
Response: The project related to Order 693 directives has pulled the EOP-003 standard.		

7. Do you agree with the revisions to EOP-003-1?

Summary Consideration:

While the standard drafting team received support for the changes to EOP-003 eliminating the redundancy between it and PRC-006 related to underfrequency load shedding requirements, some commenters indicated that the standard drafting team should clarify that the remaining requirements in EOP-003 are related to automatic undervoltage load shedding and manual under frequency load shedding. The drafting team made a conforming change to the proposed standard to clarify that the requirements exclude automatic underfrequency load shedding.

Other comments received indicated that the standard drafting team should revise the requirements related to undervoltage load shedding; however, there is a NERC project tasked with revising EOP-003 and while it is at the initial stages this team will address the requirements that require revision.

Organization	Yes or No	Question 7 Comment
Western Electricity Coordinating Council		Agree with the removal of the words underfrequency and Balancing Authority in EOP-003, but do not agree with the EOP-003-1 or the current version of EOP-003-2 that is out for vote because it still includes automatic UFLS. EOP-003-2 should include reference to manual load shed only. It includes UFLS that is undefined and could cause a conflict with PRC-006.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
MEAG Power		No comment.
Xcel Energy		No comments
Southern California Edison Company		We cannot comment on the proposed revisions to EOP-003-1, as their ramifications have not been studied in detail.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
Long Island Power Authority	No	
Wisconsin Electric Power	No	Although we agree with the intent of the revisions, EOP-003-1 needs further revision to focus this standard solely on manual loadshed. References to the development of both UFLS and UVLS programs need to be

Organization	Yes or No	Question 7 Comment
Company (dba We Energies)		removed from EOP-003-1 as PRC-006-1 will cover automatic UFLS programs and a series of other PRC standards already cover automatic UVLS programs. The SDT should delete R2, R4, R7 and M1 from the posted SDT revised draft standard EOP-003-1 as part of supplemental SAR limited scope of revising requirements related to underfrequency loadshedding. In addition, the SDT should give consideration to inserting the word "manual" in front of the words "load shedding" in R3 and R5 in the posted SDT revised draft standard EOP-003-1. The Measures and Violation Severity Level sections would need to be updated accordingly.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
MidAmerican Energy	No	Automatic load shedding needs to be left in PRC-006. Manual load shedding should be left in EOP-003 according to already existing standards proposed changes. The SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for removing the automatic UVLS requirements from EOP-003-1 and referring them to a new PRC-024-1 standard. In line with the comments for Question 6:R2 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and PRC-024-1.R3 - add the qualification "coordinate manual load shedding plans".R4 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and PRC-024-1.R5 - add the qualification "implement manual load shedding plans".R7 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and PRC-024-1
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
Ameren	No	Because EOP-003-1 is the primary load shedding standard, and because UFLS has been removed from EOP-003-1 and placed in PRC-006-1, standard EOP-003-1 should note in the "Purpose" section that UFLS is addressed in PRC-006-1.The stated purpose of EOP-003-1 is to have the capability and authority to shed load rather than risk uncontrolled failure of the interconnection if there is insufficient generation or transmission capacity. It is not clear when and how it is determined that an "automatic" load shedding scheme is necessary or required. Are all TO's required to have undervoltage load shedding plans in place? Suggest changing the ending phrase of R2 in EOP-003 from "required" to "necessary to minimize the risk of uncontrolled failure of the Interconnection." Also suggest a review of other UVLS stanadrds for consistency with revised EOP-003.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-		

Organization	Yes or No	Question 7 Comment
frequency load shedding.		
SERC Planning Standards Subcommittee	No	Because EOP-003-1 is the primary load shedding standard, and because UFLS has been removed from EOP-003-1 to PRC-006-1, standard EOP-003-1 should note in the "Purpose" section that UFLS is addressed in PRC-006-1.Suggest changing the ending phrase of R2 in EOP-003 from "required" to "necessary to minimize the risk of uncontrolled failure of the Interconnection."
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
Tri-State Generation & Transmission Assoc.	No	Comments: The revisions are adequate for the most part, but Requirement R4 needs to specify that only undervoltage load shedding is being addressed.There is also a concern that EOP-003-2 is currently being balloted based on changes made as a part of the Order 693 Directives. The two versions are not compatible.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. The project related to Order 693 directives has removed EOP-003 revisions from its scope of work.		
Bonneville Power Administration	No	EOP-003-1 and the current version of EOP-003-2 still include automatic UFLS. EOP-003-2 should include reference to manual load shed only. To include UFLS that is undefined would cause a conflict with PRC-006.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
Exelon	No	EOP-003-1 needs to define the criteria as to when and how UVLS schemes are installed to provide consistency direction to Planning Coordinators and the entities that have to install UVLS schemes. The relationship between the use of UVLS and compliance with TPL-001 standards should be clarified. Is load shedding (including UVLS) allowed to meet the performance criteria in TPL-001? The standard should define when UVLS are applicable to the BES and thus subject to the requirements of EOP-003. UVLS schemes developed for distribution or other purposes beyond criteria should not be discouraged through regulatory burden.UVLS should be carefully defined. Many types of load will cut out on low voltage.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
American Transmission Co.	No	In line with the comments for Question 6:R2 - remove this requirement because it refers to automatic load

Organization	Yes or No	Question 7 Comment
		shedding plans, let this be covered by PRC-006-1 and new PRC standard.R3 - add the qualification "coordinate manual load shedding plans".R4 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.R5 - add the qualification "implement manual load shedding plans".R7 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
Manitoba Hydro	No	In line with the comments for Question 6:R2 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.R3 - add the qualification "coordinate manual load shedding plans".R4 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.R5 - add the qualification "implement manual load shedding plans".R7 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	In line with the comments for Question 6:R2 - remove this requirement because it refers to automatic load shedding plans and let the automatic requirements be covered by PRC-006-1 and a new PRC standard.R3 - Recommend R3 be rewritten to read: Each Transmission Operator and Balancing Authority shall provide manual load shedding plans to adjacent interconnected Transmission Operators and Balancing Authorities.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
United Illuminating Company	No	R1 should use term "shall implement manual load shedding". The Drafting team note says that PRC-006 is a Planning Standard and therefore EOP-003 R1 is needed to apply to the actual implementation of automatic load shed. We disagree that PRC-006 is solely Planning. The UFLS entity is required to implement the program, meaning protective devices are deployed and armed. By creating the program and arming the protection systems the UFLS Entity has committed to load shed.EOP-003 R1 is addressing the steps or actions a Transmission Operator takes to respond to insufficient resources. The Transmission Operator does

Organization	Yes or No	Question 7 Comment
		not initiate automatic UFLS.The UFLS program is created by the Planning Coordinator and implemented by Transmission Owners and DP. EOP-003 requires the BA and TOP to perform load shed. Again, for UFLS this implies the TOP and BA have on/off control for UFLS protection systems. This we know is not true. The TOP/BA has the authority to implement manual load shed.A similar argument is made for R3. R3 should be "coordinate manual load shed plans". Coordinating plans is a Planning Horizon exercise. Therefore EOP-003 R3 coordination of ufls load shed by TOP/BA is a duplicate function to the PRC-006 coordination by Planning Coordinators. The entity with the best knowledge to coordinate UFLS is the Planning Coordinator. TOP and BA are coordinating the manual load shed plan with the recognition the UFLS is installed.In R5 add the words "automatic load shedding scheme other than UFLS". This will help compliance monitoring by explicitly differentiating this from PRC-006. Update the VSL also with this clarification.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
Western Area Power Administration	No	R2 thru R5 - is specific to under voltage conditions but the "Purpose" of the standard states is for insufficient generation along with insufficient xmsn capacity. Also the Transmission Operator does not establish plans or coordinate for auto load shedding for under voltage conditions - this is a function of PlanningR6 and R7 - now the requirements are back to under frequency along with under voltage. R8 - states the Operator shall be capable of implementing load shed adequate for responding to the EM - in most cases there is not enough time to respond manually. Is this referencing if a condition develops slowly enough to have time to respond?Seems like the purpose and requirements should be further defined so that EOP-003 is specifically for BA and Transmission Operations for developing low voltage/frequency conditions with ability/authority to shed load and PRC-006 for Planning defining auto load shed for low voltage/frequency conditions.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1.		
Pepco Holdings, Inc. - Affiliates	No	R2.3 appears to require a PC that is involved in more than one region to have an "islanding program" for its footprint in each region. What if the PC is PJM and there is a sliver a region outside RFC. Do we really need a program for the sliver? This requirement assumes without justification that RE boundaries and PC boundaries define potential islands. **Response: The intent with this approach is to ensure coordination between regions and for selecting islands that overlap adjacent regions within an interconnection.** R4 - What is a "design assessment"? Why not just require "an assessment every five years"? Why all the

Organization	Yes or No	Question 7 Comment
		extra words like "design assessment"? "conduct and document"? through dynamic simulations? **Response: The SDT thinks that the added words clarify the intent of the requirements.** R5 requires concurrence among PCs. My view is that a requirement must be to one and only one functional entity. More than one entity causes questions as to who is non-compliant when things go awry. In R5 who is non-compliant if a peer PC does not concur? **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern.** R6 Why not just require a database for UFSL data? Why must the requirement include the editorial requirement "for use in Event Analysis and assessments of UFLS program" Does that mean I MUST use the UFLS database for Event Analysis? Does it mean I can't use the data for other activities?R8 is curious to me. It stipulates that the data is provided "to support the database". I ask, isn't the data being required to support the concept that the UFLS program is up-to-date and operational? For both R6 and R8, the issue is editorial explanations in addition to the actual requirement. **Response: The SDT thinks that the added words clarify the intent of the requirements.** R12 seems to say that PC whose assessment shows a problem, that PC shall conduct an assessment (again?). The requirement then goes on to mandate the PC "consider" the deficiencies. I know what they want to say but this requirement doesn't say it to me. Can you imagine proving you "considered the deficiencies"? **Response: PRC-009 contains an assessment requirement after the actuation of UFLS.**
AECI	No	R4 says voltage or power flow levels must be considered when designing an automatic load shedding scheme. Our UFLS scheme is an automatic load shedding scheme that does not take voltage or power flow levels into account. R4 needs to be reworded so that it is clear that it is ok to have automatic UFLS schemes that do not rely on under voltage or power flow levels.
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding.		
Tennessee Valley Authority (TVA)	No	TVA supports the modifications to the EOP-003 standard which remove UFLS. We believe that EOP-003 should continue to be revised under the appropriate project to focus the emphasis on load shedding plans that are controlled by operator action, and exclude automatic protection schemes (UFLS and UVLS) that do not require operator action to execute their designed function.We have the following comments on the proposed modifications:R2 - We recommend that the text added at the end of this requirement be removed (“if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s)

Organization	Yes or No	Question 7 Comment
		determine that an under-voltage load shedding scheme is required."). This addition introduces entities that are not identified in the "Applicability" section of the standard (A.4). While simulations performed in the planning environment (TPL standards) would likely lead to this determination, references to the Transmission Planner and Planning Coordinator in this requirement will introduce compliance confusion. Can the SDT point to another standard that requires the Transmission Planner or Planning Coordinator to determine if an under-voltage load shedding scheme is required? Our preference would be to strike requirement R2 from the EOP-003 standard altogether, but we realize the scope of this project is limited to UFLS.R4 - With the deletions that are being proposed, we recommend that "undervoltage" be inserted into the requirement for clarification -- "automatic undervoltage load shedding scheme".R7 - Since the Balancing Authority has been removed, suggest changing "their areas" to "their area" (singular).
Response: The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. The Supplemental SAR approved by the Standards Committee limits the scope to removing conflicts and redundancies related to under-frequency load shedding only in EOP-003-1.		
IRC Standards Review Committee	No	We understand the concerns that EOP-003-1 contains redundant requirements. However, the Order 693 changes include revisions to EOP-003-1 that are in conflict with the supplemental SAR.
Response: The project related to Order 693 directives has removed EOP-003 from the scope of its project.		
Duke Energy	Yes	
Entergy Services	Yes	
IESO	Yes	
Oncor Electric Delivery	Yes	
Progress Energy - Carolinas	Yes	
SERC SC UFLS Standard Drafting Team	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 7 Comment
Southern Company Transmission	Yes	
SPP System Protection and Control Working Group	Yes	
Y-W Electric Association, Inc.	Yes	
FirstEnergy	Yes	Although we agree with the revisions to EOP-003 with regard to removal of underfrequency load shedding references, we believe the SDT could have improved the standard even further by developing a complete set of measures. There are currently only two measures for eight requirements. Furthermore, since EOP-003-1 is the current approved standard, and this standard would be version 2 (EOP-003-2).
Response: Thank you for your support. The standard drafting team does not think the Measures need to be modified as the team has only eliminated any inference to underfrequency load shedding in the requirements and performed a review of the Measures and determined they do not need revision.		
Northeast Power Coordinating Council	Yes	EOP 003 is on the list of standards identified by the NERC Tiger Team for fast tracking of Order 693 directives. There is concern that coordination between these two DT's may not have occurred and that the changes agreed upon in the revised UFLS SAR should also be considered by the Tiger Team.
Response: : The project related to Order 693 directives has removed EOP-003 from the scope of its project.		
Northeast Utilities	Yes	EOP 003 is on the list of standards identified by the NERC Tiger Team for fast tracking of Order 693 directives. There is concern that coordination between these two DT's may not have occurred and that the changes agreed upon in the revised UFLS SAR should also be considered by the Tiger Team.
Response: : The project related to Order 693 directives has removed EOP-003 from the scope of its project.		
Indiana Municipal Power Agency	Yes	However, changes need to be coordinated with the tiger team and their changes to EOP-003-1.
Response: : The project related to Order 693 directives has removed EOP-003 from the scope of its project.		
NERC Staff	Yes	NERC staff agrees that it is wise to revise requirements specific to Underfrequency Load Shedding in EOP-003-1 to remove inconsistencies and redundancies. The only concern is that because both the team of experts (formerly known as the Tiger Team) and the original EOP-003-1 SDT are working on modifications to

Organization	Yes or No	Question 7 Comment
		the standard, there could be some overlap and miscommunication, especially with respect to these redundancies between PRC-006-1 and EOP-003-1.
Response: : The project related to Order 693 directives has removed EOP-003 from the scope of its project.		
ReliabilityFirst Engineering Staff	Yes	Yes, the revisions that were made are appropriate. However, EOP-003 will require further substantial revisions as many of the requirements are still inappropriately assigned to the TOP such as establishing automatic undervoltage load shedding plans (R2).
Response: There is a NERC project tasked with revising EOP-003 and while it is at the initial stages this team will address the requirements that require revision. The SDT made conforming changes to EOP-003-2 to clarify that the load shedding remaining in the standard is not related to under-frequency load shedding. The Supplemental SAR is focused solely on eliminating redundancies between the two standards related to underfrequency load shedding.		

8. Based on industry supplied comments, the SDT modified the applicability of the standard from "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" and "Distribution Providers" in the second posting to "UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include Transmission Owners and/or Distribution Providers" in an effort to more appropriately identify those entities responsible for providing UFLS coverage. Has the SDT correctly identified the proper entities for UFLS coverage?

Summary Consideration:

Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.

Organization	Yes or No	Question 8 Comment
The California ISO	No	1) Applicability of the proposed Standard PRC-006-1 should also apply to Load Serving Entities (LSEs) for underfrequency load shedding.2) Applicability of the proposed Standard PRC-006-1 should also apply to Generator Owners since GOs would need to be involved for overfrequency generation tripping.3) Applicability of the proposed Standard PRC-006-1 should also apply to the Reliability Assurer/Regional Reliability Organization (RRO). (WECC in our case).4) The Reliability Assurer/Regional Reliability Organization (RRO) should be the entity that coordinates the UFLS programs.
Response: 1)The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons." **2) The responsibility of generator owners resides within a standard under development currently, PRC-024. Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.** **3) Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES. This standard is under development as a direct result of this particular issue and was identified as a part of a set of standards for having "fill in the blank" requirements. The SDT has crafted Requirements R5 and R13 to allow for and encourage coordination among**		

Organization	Yes or No	Question 8 Comment
PCs. This standard does not preclude the RRO/RA from performing this coordination function, but does not include a requirement for the RRO/RA for this purpose. **4) This option is not precluded from the standard as it is written. However, ultimate responsibility for developing UFLS programs lies with the Planning Coordinators.**		
Entergy Services	No	1. We recommend that R3 be revised to require the PC to specifically notify the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. **Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.** 2. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information. **Response: Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.**
Y-W Electric Association, Inc.	No	Because Load Serving Entities (not Distribution Providers) are actually responsible for the load in the current Functional Model and Compliance Registry Criteria, they should also be included in the applicability section of this standard.
Response: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.		
Tri-State Generation & Transmission Assoc.	No	Comments: We believe that "ownership" should be removed from the criteria because it may be different from the operating or controlling entity and both entities cannot be responsible. **Response: The SDT's intent was to adequately capture the entities which "own, operate or control" UFLS equipment. In the sense it is written here, 'control' of the relay setpoints is the critical distinction as the relays operate once a predetermined set of system conditions has been achieved.**

Organization	Yes or No	Question 8 Comment
		Load Serving Entities should also be included as a "possible" UFLS entity Some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. **Response: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons** This should remain the responsibility of the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate nor address the interconnection reliability needs. **Response: Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES. This standard is under development as a direct result of this particular issue and was identified as a part of a set of standards for having "fill in the blank" requirements. The SDT has crafted Requirements R5 and R13 in order to allow for and encourage coordination among PCs. This standard does not preclude the RRO/RA from performing this coordination function, but does not include a requirement for the RRO/RA for this purpose.**
IRC Standards Review Committee	No	Generator owners are not included in the applicability of this standard. We understand from the SDT's responses to the last posting that there is a separate project for generator requirements that could obligate them to provide required data to planning coordinators for underfrequency load shedding schemes. However, absent that standard, a generator owner has no obligation to provide needed data to a planning coordinator. If the generator owner fails to provide that data, then that planning coordinator could be found in violation of a requirement in PRC-006-1. NERC must recognize that registered entities may vote against PRC-006-1 if they are concerned about the ability to meet requirements which rely on yet to be approved or developed standards and/or definitions. Therefore, in a concerted effort to move proposed standards through the approval process, NERC must not enforce specific requirements upon a registered entity if that entity cannot meet a requirement because a supporting standard or definition is not yet in effect. **Response: GO applicability lies within the PRC-024 standard currently under development. Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not**

Organization	Yes or No	Question 8 Comment
		come into effect until after PRC-024 is approved. We are also concerned that the ULFS standards requirements may not apply to new entities and loads that may be interconnected to the BPS such as those for Demand Response grid services. New technologies such as Smart Grid and Plug-In Electric Vehicles will become more prevalent in the near future and new entities may be aggregating these loads to offer grid services. Because it is unknown how these aggregators may be structured, they may not fall into the registered entity categories specified in this standard. NERC should be diligent in identifying new entities that existing approved standards should apply to and adjust the registry and standards accordingly. **Response: Thank you for your comment.**
IESO	No	Generator owners are not included in the Applicability Section of this standard. We understand from the SDT's responses to the last posting that there is a separate project for generator requirements that would obligate them to provide the required information to the Planning Coordinators with which to design the underfrequency load shedding program. Absent that standard, a Generator Owner has no obligation to provide the necessary data to the Planning Coordinators which can result in the Planning Coordinator failing to meet the PRC-006-1 standard. We therefore request that Generator Owner be included in the Applicability Section and a requirement for it to provide the needed information to the Planning Coordinator be added, or balloting of standard PRC-006-1 be deferred until such a requirement in that other standard is ready for balloting. **Response: GO applicability lies within the PRC-024 standard currently under development. Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.** The reason for including Transmission Owners in Section A 4.3 after they have been identified in Section A 4.2 is unclear or not needed. **Response: The SDT added this additional distinction for the purposes stated in Requirement R10. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.**
AECI	No	It seems like generator owners should be added here, especially since R4 deals with generator frequency settings
Response: GO applicability lies within the PRC-024 standard currently under development. Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.		

Organization	Yes or No	Question 8 Comment
Bonneville Power Administration	No	LSE should also be included as a "possible" UFLS entity some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. **Response: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.** In addition to the issue previously stated concerning PC authority, no valid way exists to determine which registered entities are under the jurisdiction and authority of any Planning Coordinator. The current version does not address customer-owned UFLS relays. There should be recognized sub-area group(s), which consists of PCs, as assigned by the Regional Assurer (RA) which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off-Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate nor address the interconnection reliability needs. **Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES. This standard is under development as a direct result of this particular issue and was identified as a part of a set of standards for having "fill in the blank" requirements. The SDT has crafted Requirements R5 and R13 in order to allow for and encourage coordination among PCs. This standard does not preclude the RRO/RA from performing this coordination function, but does not include a requirement for the RRO/RA for this purpose.**
Western Electricity Coordinating Council	No	LSE should also be included as a "possible" UFLS entity Some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. **Response: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.** There should be a recognized sub-area group(s), which consist of PCs, as assigned by the Regional Assurer

Organization	Yes or No	Question 8 Comment
		(RA) which is the agent(s) for overall coordination within the interconnection or sub-area. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate nor address the interconnection reliability needs. **Response: Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES. This standard is under development as a direct result of this particular issue and was identified as a part of a set of standards for having "fill in the blank" requirements.**
Tennessee Valley Authority (TVA)	No	Our preference is that the applicability section of the standard remain "clean" with regard to the applicable entities listed, and not cluttered with qualifiers. For instance, we see no benefit in listing Transmission Owners twice (4.2.1 and 4.3).If this format is retained, we suggest that section 4 be revised to add clarity. We suggest that section 4.2 be revised to read:"UFLS entities shall mean all entities that are responsible for the ownership, design, or installation of UFLS equipment or automatic switching of Elements as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers"and that 4.3 be deleted. **Response: The SDT added this additional distinction for the purposes stated in Requirement R10. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** The terms "operation" and "control" are typically used in the context of an operating entity task (RC, TOP, GOP, BA). Therefore we prefer the use of "ownership, design, and installation" over "ownership, operation, or control". **Response: The SDT intent was to adequately capture the entities which "own, operate or control" UFLS equipment. In the sense it is written here, 'control' of the relay setpoints is the critical distinction as the relays operate once a predetermined set of system conditions has been achieved.** The omission of the Generator Owner from this standard is potentially problematic in that coordination with generator under- / over-frequency settings is needed. **Response: Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.** We also note that PRC-008-0 contains the phrase "required by its Regional Reliability Organization to have a UFLS program". Should this be changed to "required by its Planning Coordinator to have a UFLS program" to align with the proposed changes to PRC-006-1? **PRC-008 will be addressed as a part of project 2007-17, Protection System Maintenance and Testing,**

Organization	Yes or No	Question 8 Comment
		which is currently out for ballot. Lastly, with the modifications to EOP-003, there is no linkage of operating entity applicability to UFLS. While beyond the scope of this drafting team's objectives, we believe that operator awareness of UFLS installations is a critical component of load restoration following an event that initiates UFLS tripping. **FERC order 693 is directing the changes to EOP-003. Also, operator action during system restoration typically occurs well after UFLS has attempted to arrest frequency decline during an underfrequency event.**
Southern California Edison Company	No	SCE agrees with WECC's position that "the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered, the LSE needs to be included in the Applicability section".
Response: The SDT recognizes that the Functional Model version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.		
Northeast Power Coordinating Council	No	Significant amounts of UFLS capability may fall outside the current FM design, and the DT is trying to capture all entities that control UFLS in its applicability requirements. In spite of this effort ambiguity still exists in the applicability regarding the broad statement pertaining to UFLS entities that 'control' UFLS equipment.
Response: The SDT intent was to adequately capture the entities which "own, operate or control" UFLS equipment. In the sense it is written here, 'control' of the relay setpoints is the critical distinction as the relays operate once a predetermined set of system conditions has been achieved. **In an effort to remove some ambiguity in this regard, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.**		
MidAmerican Energy	No	The word "all" should be replaced with "applicable". The compliance requirement should focus on primary entity identified responsible for that compliance function. An example, might include a jointly owned facility (generator, substation, line, transformer, or capacitor bank) owned by one or more entities and operated by another. One identified entity should be identified and held responsible its UFLS relays whether through majority ownership, interconnection agreements, or contracts. Since ownership and operation can be divided, it is inappropriate to enforce compliance responsibilities on entities outside of their control.

Organization	Yes or No	Question 8 Comment
Response: The SDT cannot comment on contractual issues, however, in an effort to remove some ambiguity regarding UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.		
Xcel Energy	No	We question why Generator Owners are not included as a UFLS entity. Under R4 PCs are required to obtain setting from them. We are not aware of another standard that requires GOs to provide those settings to the PC. Thus there should also be a requirement indicating that GOs (or UFLS Entities) provide data requested by the PC to conduct the required assessments.
Response: Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.		
FirstEnergy	No	We support the applicability section of the standard as asked per this question. However, we do not see any question for general comments and have comments and suggestions regarding the proposed implementation plan for the applicable UFLS entities and Transmission Owners that own Elements identified in the UFLS program. 1. Although we agree that the Planning Coordinator is the appropriate functional entity to develop and implement a UFLS program, we are concerned with the fact that UFLS entities may not know the specifics of their responsibilities until long after this standard is approved. The SDT should consider adjusting the language of the standard to require more transparency and coordination with the UFLS entities during the PC's development of the UFLS program. Also, per the implementation plan, the PC will be given one year to develop its UFLS program. However, the timeframe for the UFLS entity is based on the schedule imposed by the PC. The implementation plan should allow the UFLS entity at least one year (maybe more per capital budget cycles) from the time the PC identifies the UFLS entity in their UFLS program. The UFLS entity will need sufficient lead time in those instances that require purchase of new UFLS equipment that will require long term budget planning for implementation. **Response: The SDT understands your concern and has added Requirement R14, which requires notification of UFLS entities of the UFLS program design and schedule for application and a requirement to respond to feedback received.** 2. The UFLS entities are identified in the UFLS program established by the PC. However, it is not clear where the PC is explicitly required to notify and coordinate with the UFLS entity. In Requirement R3 it is implied that the PC will notify and coordinate with the UFLS entity per the phrase "including a schedule for implementation by UFLS entities within its footprint". This requirement needs to be more explicit that the PC will notify the UFLS entity, and the measure for R3 needs to require proof that the PC has done this. **Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and**

Organization	Yes or No	Question 8 Comment
		response to feedback received.
SPP System Protection and Control Working Group	No	Why are Generator Owners not included in the Standard? The Planning Coordinator can't prove the design without the Generator Owner for Requirements R3 and R4.
Response: Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.		
Ameren	Yes	
American Transmission Co.	Yes	
Duke Energy	Yes	
Exelon	Yes	
Long Island Power Authority	Yes	
Manitoba Hydro	Yes	
MRO's NERC Standards Review Subcommittee (NSRS)	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC Planning Standards Subcommittee	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 8 Comment
United Illuminating Company	Yes	
Wisconsin Electric Power Company (dba We Energies)	Yes	
Indiana Municipal Power Agency	Yes	IMPA believes that this draft allows entities who are currently providing UFLS at the transmission level to stay in place and provide this service going forward. IMPA hopes that the Planning Coordinators will establish their UFLS program by using this current UFLS setup prvided by Transmission Owners and not force a financial burden onto Distribution Providers by requiring then to install UFLS equipment. In states such as Indiana and Illinois, UFLS is performed at the transmission level for some entities and includes all the distribution load in the area regardless of size and voltage connection to the BES.
Response: Thank you for your support.		
NERC Staff	Yes	NERC staff believes that the SDT has sufficiently identified the proper entities for UFLS coverage. NERC staff understands the comments raised by the industry regarding transfer of responsibilities, however, it is worth noting that some inconsistency has been created by the language used in the standard. It could be problematic that the entity with the original responsibility (the Distribution Provider) can delegate responsibility to another entity (the Transmission Owner), because even with that delegation, the Distribution Provider's original responsibility does not disappear.
Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.		
Illinois Municipal Electric Agency	Yes	Tbe SDT's consideration of comments during the second posting is very much appreciated. Applicability now reoognizes and preserves the widely used practice of a TO factoring interconnected DP (that does not own or operate UFLS equipment) load into the TO UFLS scheme.
Response: Thank you for your support.		
MEAG Power	Yes	This is an excellent language change.
Response: Thank you for your support.		
SERC SC UFLS Standard	Yes	We recommend that R3 be revised to require the PC to specifically notify the "UFLS Entities" in their PC area

Organization	Yes or No	Question 8 Comment
Drafting Team		that are part of the PC's UFLS program.
Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.		
Southern Company Transmission	Yes	We recommend that R3 be revised to require the PC to specifically notify the "UFLS Entities" in their PC area that are part of the PC's UFLS program.
Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.		
Progress Energy - Carolinas	Yes	We recommend that R3 be revised to specifically require the Planning Coordinator to notify the "UFLS entities" in their PC area that they are part of the PC's UFLS program.
Response: In an effort to remove some ambiguity in regard to UFLS entity applicability, the SDT has added Requirement R14 which requires notification of UFLS entities of the UFLS program design and response to feedback received.		

9. The SDT has modified the performance characteristics in Requirements R6.1 through R6.3 (now parts 3.1, 3.2 and 3.3 of Requirement R3) and the modeling requirements for generator underfrequency and overfrequency protection in Requirement R7.1 and R7.2 (now parts 4.1 through 4.6 of Requirement R4). The modifications replace the discrete points in these requirements with frequency-time curves that achieve the same reliability objective. The SDT agrees with several commenters in the second posting that this approach is easier to understand and better demonstrates the coordination the SDT has achieved with the requirements proposed by the Generator Verification SDT in proposed standard PRC-024. Do you agree with these changes?

Summary Consideration:

As a result of the comments received, the SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the Planning Coordinator to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.

Organization	Yes or No	Question 9 Comment
Xcel Energy		No comments
Long Island Power Authority	No	
Western Area Power Administration	No	
GDS Associates	No	- See the answer to question 10. pertaining the classification of generating units / plants
Response: See response to question 10		
MRO's NERC Standards Review Subcommittee (NSRS)	No	1. In R3, simply say that the "program shall shed at least 25% of island load" and avoid use of the formula. If the formula is retained, then we suggest that it be changed to the more common industry nomenclature of "imbalance = (load-generation)/generation."

Organization	Yes or No	Question 9 Comment
		2. In R4, we interpret that the Equivalent Inertia Analysis is a valid dynamic simulation methodology for certain aspects of UFLS assessments. This is a methodology that is often recommended in relay application guides and other technical references. Please clarify that this type of dynamic analysis would be accepted toward compliance with the "through dynamic simulation" portion of this requirement. For Attachment 1 (R4.1, R4.2 & R4.3) and Attachment 2 (R4.4, R4.5 & R4.6)3. Attachment 1 and 2 include transient frequency performance curves for at least 30%, 40% and 50% island imbalance. Otherwise, revise the titles for Attachments 1 and 2 to clearly qualify that the transient frequency performance curves apply for a 25% or less island imbalance and that programs which are larger than this minimum load shedding requirement do not have to meet this criteria when overloads are in excess of 25%. In addition, UFLS programs that are designed for appropriate performance under imbalance conditions above 25% will not have the same performance curves as programs that are designed for imbalance conditions of 25% or less. 4. If item #3 is not adopted, then the Under Frequency Performance Characteristic line in Attachment 1 should be extended from the knee at approximately 58.9 Hz (for 60 seconds) to 59.3 Hz or 59.5 Hz (for approximately 500 sec). The purpose is to define a single line of constant slope and to get rid of the arbitrary knee in the characteristic curve which serves no reliability purpose. The reason for this change is that the worst case frequency recovery time for frequencies between 58.7 Hz and 59.5 Hz may occur for imbalance conditions significantly less than 25% where the governor response prevents the load shedding blocks from picking up and where frequency recovery times are a function of governor response and system inertia. Likewise, it makes sense to extend this line below 58 Hz to at least as low a frequency as is covered by the generation protection curve. 5. Add a note to Attachment 1 that states, "Larger size UFLS programs (e.g., 40%) may require less restrictive (lower) underfrequency (as well as and/or longer time delays) due to island generation and protection characteristics. UFLS programs shedding more than 25% must also increase generation protection delay times and/or change set points to achieve coordination with load shedding. For example, Manitoba Hydro and Saskatchewan need to shed more than 30% of the area load to achieve reasonable frequency recovery in their islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable.Generator Underfrequency and Overfrequency Coordination Attachments 6. The Generation Owner off-nominal frequency coordination requirements and coordination curves should be included only in the PRC-006 standard and not the PRC-024 standard. The generator coordination curves relate directly to the PRC-006 assessment requirements and the PRC-006 curves will be duplicative of, and possibly contradictory to, the curves in the PRC-024 standard if they are finally approved and then changed in the future. 7. The generation coordination curves need to be appropriate for the different types of UFLS programs (e.g.

Organization	Yes or No	Question 9 Comment
		25%, 30%, 40%, 50%, etc.) that have, or will be, designed and implemented for different islands. Generation coordination curves for 25% UFLS programs will not be the same for other (e.g. 30%, 40%, 50%) UFLS programs. It can be demonstrated that as the size of the load shedding program is increased, the generation protection settings have to be modified accordingly to achieve the coordination objectives. UFLS programs that are designed for imbalances greater the 25% inherently require lower minimum frequencies and longer frequency recovery times 8. If item #7 above is not adopted, then revise the titles for generation coordination curves to clearly qualify that they apply for a 0% to 25% island imbalance and that programs which are larger than this minimum load shedding requirement do not have to meet this criteria when overloads are in excess of 25%. The generation protection line should extend to 57 Hz (at .3 sec) to 59.5Hz (at 1800 sec). The minimum frequency of 57.0 Hz was chosen because most conventional generation can briefly operate down to 57.0 Hz and large load shedding programs may need to make use of that capability to achieve coordination with these UFLS programs. 9. We are aware of the technical basis for the generator Under Frequency protection setting, but not aware of the technical basis for the presently proposed generation coordination curves in PRC-006 or PRC-024. We suggest that the SDT provide the industry with the technical basis for the generation coordination curves. We are concerned that the curves allow enough time for load shedding to operate under “worst case conditions”, and as much time as possible needs to be given for frequencies close to 60 Hz. We are also concerned that for actual UFLS events system frequency recovery may stall below 59.5 Hz for a long time while operators try to deal with event with manual shedding of load. Volts/Hertz Performance Characteristic 10. The Volts/hertz requirement is not needed in this standard and should be removed for several reasons: [1] Voltage regulators automatically reduce voltage according to volts per hertz when in the automatic mode so they self protect. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist that adequately address the volts/Hz issue. [2] If voltage regulators are in automatic, then the 110% volts/Hz limit becomes active between 57.2 Hz and 51.8 Hz assuming the voltage regulator holds terminal voltage within the allowed 1.05 p.u. to 0.95 pu range. [3] Units with voltage regulators in manual will just trip when volts per Hertz protection picks up. However, units are normally in the automatic control mode per NERC Standards. [4] It appears this requirement is appropriate for programs which may experience frequencies below 57.2 Hz, but few, if any, programs are expected to be designed for frequencies that are this low. [5] Even if UFLS programs are designed for frequencies below 57.2 Hz, this performance characteristic cannot presently be properly simulated in stability cases as the voltage regulator V/Hz controls are not

Organization	Yes or No	Question 9 Comment
		presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation
Response: The SDT is specifying a minimum requirement of a 25% imbalance to design the UFLS program to. Regional standards can be developed to define include larger imbalances. The formula provided in the standard adds clarity. Our interpretation is that Equivalent Intertia Analysis is not sufficient to meet all of the requirements of the standard. We have clarified the language of R4 and the knee of the curves in Attachment 1 to clarify that the UFLS program should be designed such that a steady state frequency between 59.3 and 60.7 Hz is reached within 60 seconds. The SDT believes there is a need for V/Hz requirements because shedding load will cause voltages to climb, which may cause excitation systems / voltage regulators to reach the end of their range, which can lead to a V/Hz condition that could cause generators to trip through GSU protection or other similar protection systems. Therefore, the SDT believes that V/Hz of 1.18 p.u for 2 seconds, etc., can be reached at significantly higher frequencies than 57.2 Hz. The standard does not require modeling of V/Hz protection and only requires monitoring of voltage and frequency and designing the UFLS program to meet the performance criteria described in 3.2. No changes made.		
American Transmission Co.	No	1. In R3, the term, “imbalance”, should be described using the standard industry nomenclature of imbalance = (load-generation)/generation. 2. In R4, we interpret that the Equivalent Inertia Analysis is a valid dynamic simulation methodology for certain aspects of UFLS assessments. So, we expect that this type of dynamic analysis would be accepted toward compliance with the “through dynamic simulation” portion of this requirement Attachement 1 for R4.1, R4.2, R4.33. The title for Attachment 1 should clearly qualify that this curve applies for a 25% or less island imbalance. The curves that should be used for UFLS programs associated with imbalance levels greater than 25% (e.g. 30%, 40%, 50%) would be different from the 25% curve. 4. The Under Frequency Performance Characteristic line in Attachment 1 should be extended to 59.5 Hz (at 500 sec). The reason for this change is that the worst case response between 58.7 Hz and 59.5 Hz may occur for imbalance conditions significantly less than 25% where the governor response prevents the load shedding blocks from picking up and where response recovery times is a function of governor response and system inertia (30 seconds to 500 seconds). This removes the knee of the curve at 30 seconds and extends the curve up to 500 seconds. This would change the 30 second at 58.9 Hz cut off point to 500 seconds. 5. Add a note to Attachment 1 that states, "Larger size UFLS programs (e.g., 40%) may require less restrictive (lower and/or longer time delays) underfrequeny limits due to island generation and protection characteristics." UFLS programs shedding more than 25% must increase generation protection delay times and/or change set points to achieve coordination with load shedding. For example, Manitoba Hydro and Saskatchewan need to shed more than 30% of the area load to achieve reasonable frequency recovery in their islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable.Attachment 2 for R4.4, R4.5, R4.66. The title for Attachment 2 should clearly qualify that this

Organization	Yes or No	Question 9 Comment
		curve applies for a 25% or less island imbalance. The curves that should be used for UFLS programs associated with imbalance levels greater than 25% (e.g. 30%, 40%, 50%) would be different from the 25% curve. Generator Underfrequency and Overfrequency Attachments 7. The Generation Owner off-nominal frequency coordination requirements and coordination curves should be included in the PRC-006 standard. The generation curves should be applicable for load shedding levels beyond the 25% (e.g. 30%, 40%, 50%). If curves beyond 25% are not include, then the titles of the curves should qualify that they apply for 25% imbalance and include an note regarding coordination with UFLS programs that shed higher than 25% of the island load. The line should extend to 57 Hz (at .3 sec) to 59.5Hz (at 1800 sec). The minimum frequency of 57.0 Hz was chosen because most conventional generation can briefly operate down to 57.0 Hz and large load shedding programs may need to make use of that capability to achieve coordination with these UFLS programs.Volts/Hertz Performance Characteristic 8. The Volts/Hz requirement should be removed. This performance characteristic cannot presently be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation. In addition, the Volts/hertz requirement is not need in this standard. Voltage regulators automatically reduce voltage according to volts per hertz when in the automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist that adequately address the volts/Hz issue.
Response: The SDT is specifying a minimum requirement of a 25% imbalance to design the UFLS program to. Regional standards or Variances can be developed to include larger imbalances. Our interpretation is that Equivalent Intertia Analysis is not sufficient to meet all of the requirements of the standard. We have clarified the language of R4 and the knee of the curves in Attachment 1 to clarify that the UFLS program should be designed such that a steady state frequency between 59.3 and 60.7 Hz is reached within 60 seconds. The SDT believes there is a need for V/Hz requirements because shedding load will cause voltages to climb, which may cause excitation systems / voltage regulators to reach the end of their range, which can lead to a V/Hz condition that could cause generators to trip through GSU protection or other similar protection systems. Therefore, the SDT believes that V/Hz of 1.18 p.u for 2 seconds, etc., can be reached at significantly higher frequencies than 57.2 Hz. The standard does not require modeling of V/Hz protection and only requires monitoring of voltage and frequency and designing the UFLS program to meet the performance criteria described in 3.2. No changes made.		
Manitoba Hydro	No	1. In R3, the term, “imbalance”, should be described using the standard industry nomenclature of imbalance = (load-generation)/generation. The present definition defines imbalance as being the same as the required percent load to be shed, and if this is what is intended, it would be better to keep it simple say that everyone needs to shed at least 25% load and avoid use of the term imbalance. In any event, the definition of “imbalance” should follow industry conventions for consistency. 2. For R4.1, R4.2, R4.3 - Attachment 1 and 2:2. The titles for Attachment 1 and 2 should clearly qualify that the transient frequency performance curve applies for a 25% or less island imbalance and that programs

Organization	Yes or No	Question 9 Comment
		which are larger than this minimum load shedding requirement do not have to meet this criteria when overloads are in excess of 25%. [If the SDT doesn't allow different characteristics for a higher than 25% program, then we propose that the MRO submit a variance for a 30% and higher UFLS programs.] We are quite concerned that the generation tripping curve part of attachments 1 and 2, which matches the curve in PRC-024, as it appears to that this applies to all overload levels and to any size of load shedding program. It can be easily demonstrated that as the size of the load shedding program is increased, that generation protection settings have to be modified accordingly. The reason is to achieve coordination objectives. When we are dealing with the larger imbalances we are also inherently dealing with lower minimum frequencies and longer frequency recovery times. To make matters worse, we are trying to approve PRC-006 using information from PRC-024 which is still a draft, not an approved standard.We would like to elaborate on problems related to the generation protection curve part of attachment 1: UFLS programs have to deal with several mutually conflicting objectives and by setting hard and fast limits for generation underfrequency protection up front, we are adding an unnecessary constraint which will have undesirable effects on other aspects of the program. Such generation protection settings have to be considered in the context of the overall set of compromises that go into UFLS program design. We have to consider what kind of frequency recovery can be achieved with a well coordinated load shedding program and we have to compare that performance to the true capabilities of the generation in the island. When all things are considered, a final compromise can be reached that gives the best of all worlds. The characteristic in PRC-024 is not representative of the raw data from the manufacturers that defines actual capabilities, instead it is just someone's estimation of what is a reasonable tradeoff, and represents some hypothetical amount of accelerated loss of life of the turbine. The generation protection curve from PRC-024 is at best a starting point. From a design perspective, we could use different and equally valid settings if needed. 3. 3. The Under Frequency Performance Characteristic line in Attachment 1 should be extended from the knee at approximately 58.9 Hz (for 60 seconds) to 59.3 Hz or 59.6 Hz (at for approximately 500 sec). The purpose is to define a single line of constant slope and to get rid of the arbitrary knee in the characteristic which serves no reliability purpose. The reason for this change is that the worst case frequency recovery time for frequencies between 58.7 Hz and 59.5 Hz may occur for imbalance conditions significantly less than 25% where the governor response prevents the load shedding blocks from picking up and where frequency recovery times is are a function of governor response and system inertia. Likewise it makes sense to extend this line below 58 Hz to at least as low of a frequency as is covered by the generation protection curve spicily for the hydro generator as of Manitoba Hydro case. 4. 4. Add a note to Attachment 1 that states, "Larger size UFLS programs (e.g., 60%) may require less restrictive (lower) underfrequency (as well as and/or longer time delays) due to island generation and protection characteristics. UFLS programs shedding more than 25% must also increase generation protection delay times and/or change set points to achieve coordination with load shedding. For example, Manitoba Hydro needs to shed more than 30% of the area load to achieve reasonable frequency recovery

Organization	Yes or No	Question 9 Comment
		in it island. In this case, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable.For R4.4, R4.5, R4.6 - Attachment 2: Generator Underfrequency and Overfrequency Attachments: 5. 5. The Generation Owner off-nominal frequency coordination requirements and coordination curves should be included in the PRC-006 standard and PRC-024 should be scrapped. How can PRC-006 even proceed with using curves from PRC-024 when PRC-024 is still being drafted and subject to change? We could approve PRC-006 only to find subsequent changes to PRC-024 have undermined everything. The generation curves which are used to set generation underfrequency protection need to be appropriate for the system studied and one size does not fit all. The generation protection curves in Attachments 1 and 2 appear to be someone's personal estimation of what is a reasonable amount of accelerated loss of life per event but the flaw is that this was developed without first finding out what is really needed to ensure a well coordinated UFLS plan that meets all of the other objectives (planning engineers need to be able to coordinate generation protection with load shedding frequency recovery times as part of the study process, as the recovery times are influenced by the design objectives of the UFLS program). This generation off-nominal frequency characteristic is not what manufacturers provide as limits on their machines. No technical justification was ever provided for these curves that were developed in PRC-024, and that justification is needed. It is insufficient to say that PRC-006 is justified in using this just because it came from PRC-024. The technical justification was never part of any NERC standards drafting effort. Limits of this nature should not be created arbitrarily, and have to be selected as part of the overall final compromise involved in UFLS design to ensure we give enough time for load shedding to operate under worst case conditions, and as much time as possible needs to be given for frequencies close to 60 Hz as UFLS events show that in the real world that things do not always work as planned and system frequency can stall out below 59.5 hz for a long time while operators try to deal with this by manually shedding load. If the generation protection curves are not appropriate for programs covering overloads beyond 25%, then the titles of the curves should qualify that they apply for a 0% to 25% imbalance and include an note that different settings may be needed to coordinate with UFLS programs that shed more than 25% of the island load. Volts/Hertz Performance Characteristic: 6. The Volts/hertz requirement is not need in this standard. There are a couple of reasons. Voltage regulators automatically reduce voltage according to volts per hertz when in the automatic mode so they self protect. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist that adequately address the volts/Hz issue. If voltage regulators are in automatic, the 110% volts/Hz limit kicks in between 57.2 Hz and 61.8 Hz assuming the voltage regulator holds terminal voltage within the allowed 1.05 pu to .95 pu range. Units with voltage regulators in manual will just trip when volts per Hertz protection picks up. Units are normally in automatic control so this is not a big worry. It appears this requirement is appropriate for programs which may experience frequencies below 57.2 Hz, but few programs will see frequencies this low. Of course that makes it very

Organization	Yes or No	Question 9 Comment
		easy to demonstrate that programs satisfy this requirement, but it still seems there is no need to put this in the standard.As such, we believe the Volts/Hz requirement is of questionable worth for programs covering overloads of up to 25%, and should be removed. Even if system frequency were to drop below 57.2 hz, this performance characteristic cannot presently be properly simulated in stability cases as the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation.
Response: The SDT is specifying a minimum requirement of a 25% imbalance to design the UFLS program to. Regional standards (or Variances) can be developed to include larger imbalances. Our interpretation is that Equivalent Intertia Analysis is not sufficient to meet all of the requirements of the standard. We have clarified the language of R4 and the knee of the curves in Attachment 1 to clarify that the UFLS program should be designed such that a steady state frequency between 59.3 and 60.7 Hz is reached within 60 seconds. The SDT believes there is a need for V/Hz requirements because shedding load will cause voltages to climb, which may cause excitation systems / voltage regulators to reach the end of their range, which can lead to a V/Hz condition that could cause generators to trip through GSU protection or other similar protection systems. Therefore, the SDT believes that V/Hz of 1.18 p.u for 2 seconds, etc., can be reached at significantly higher frequencies than 57.2 Hz. The standard does not require modeling of V/Hz protection and only requires monitoring of voltage and frequency and designing the UFLS program to meet the performance criteria described in 3.2. No changes made.		
ReliabilityFirst Engineering Staff	No	1. It is not clear how the PC is supposed to enforce performance characteristic 3.3. Part 3.3 is written based on general over-excitation limits for generators and transformers. However, entities should already have over-excitation protection on critical equipment. Isn't the owner obligated to protect its equipment? Also, V/Hz at a bus is not a standard output of dynamic stability programs making it difficult to ensure compliance to part 3.3. It would be more useful if part 3.3 was expressed in terms that are commonly available such as voltage. Additionally, the meaningful per unit voltage is the machine or equipment base and the results would need to be scaled from the system base voltages. 2. The reliance on curves in Attachments 1 and 2 is imprecise. The frequency and time coordinates of each change in slope should be given so that entities do not need to interpret it themselves.3. The standard relies too heavily on the possible implementation of proposed standard PRC-024.4. The proposed PRC-006-1 UFLS standard and companion PRC-024 establish tightly defined performance characteristics which at best will just barely work for 30% UFLS programs using 3 steps of 10% load shedding. More precisely, it works for a 30% UFLS program for a range of conditions, but not for all of the conditions that can exist or are expected to exist in various portions of ReliabilityFirst over the next five years. Thus, ReliabilityFirst staff believes that these performance characteristics coupled with declining governor response and declining equivalent inertia in the Eastern Interconnection, will encourage a redesign of one or both of the existing 30% UFLS programs within ReliabilityFirst.
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a		

Organization	Yes or No	Question 9 Comment
UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachement 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters. No changes made.		
Northeast Power Coordinating Council	No	Although the DT's decision to replace the discrete points in these requirements with frequency time curves that achieve the same objective, the applicability requirement in Requirement R3.3, which addresses Volts per Hz performance characteristics, lists each generator bus and generator step-up transformer high-side bus associated with generating facilities defined in sub-requirements 3.3.1, 3.3.2, and 3.3.3. The facilities listed in the above sub-requirements appear to be quoted from the NERC Statement of Compliance Registry Criteria, Sections III.c.1 & III.c.2. It is not clear why sub requirement 3.3.3 is necessary since it is simply a restatement of requirement 3.3.2. Suggest that 3.3.3 be eliminated and that 3.3.2 be re-written to be consistent with the Registry, Section III.c.2, "Generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating."
Response: The SDT believes Requirememnt R3, Parts 3.3.1 through 3.3.3 are consisent with the Statement of Compliance Registry.		
Bonneville Power Administration	No	Each interconnection should establish discrete set points based upon stability and dynamic analysis. Discrete set points can help establish criteria which are measurable and performance-based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC. The Standard needs to be very explicit that the curves are interconnection performance curves and not entity specific set points. What is the technical justification and correlation of the curves to the UFLS Plans, i.e. where did these curves come from?
Response: The SDT believes that the degree of diversity in systems of various regions, particularly in the Eastern Interconnection, makes the determination of UFLS program design parameters an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design. The under and over frquency performance curves are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points. The over and under frequency versus time performance curves for UFLS were determined to coordinate with the Generator under and over frequency tripping curves (which have been also coordinated with the PRC-024 SDT) and to set a margin between the UFLS and generator curves.		

Organization	Yes or No	Question 9 Comment
Tri-State Generation & Transmission Assoc.	No	Each interconnection should establish discrete set points based upon stability and dynamic analysis. From discrete set points one can establish criteria which are measurable and performance based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC. Furthermore, the Standard needs to be very explicit that the curves are interconnection performance curves and not specific protective relay set points.It is recommended to combine Attachment 1 and Attachment 2 (which contain discrete set points) into a single graph, making frequency the abscissa, and requiring simulations to maintain frequencies inside the resulting envelope.R3.3. While the concern for loss of additional generation units because of their V/Hz protection schemes is understood, the bases for the 1.18pu and 1.1pu values are not evident and may not be technically supportable when compared against actual protection settings or allowable post-contingency voltage bands. Further, V/Hz protection settings vary across the system and it is unlikely adherence to this requirement will impact reliability. It will only increase dynamic analysis requirements. We recommend removing R3.3.
Response: The SDT believes that the degree of diversity in systems of various regions, particularly in the Eastern Interconnection, makes the determination of UFL:S program design parameters an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design. The SDT intends to combine Attachments 1 and 2 into one Attachment. The under and over frquency performance curves are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points. Requirement R3, Part 3.3 is based on IEEE guidelines for setting V/Hz protection. The SDT has debated the question of Requirement R3, Part 3.3 and has decided to retain the V/Hz requirement. The SDT is aware that there have been instances in UFLS studies where V/Hz has been seen as a risk to the tripping of generation and does not wish to leave a possible gap in reliability.		
IESO	No	If the overfrequency characteristics are retained, it would be better to combine Attachment 1 and Attachment 2 into one curve. The curves without some explanation may not be consistently interpreted. Should the level line at the shortest times (e.g. < 2 s) and vertical line at the longest time (e.g. > 60s) for the Performance Characteristic be interpreted to mean UFLS tripping is permitted without delay below 58.0 Hz and is not permitted above 59.3 Hz?
Response: The SDT intends to combine Attachments 1 and 2 into one Attachment. The under and over frquency performance curves are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points.		
AECI	No	It is unclear what the system frequency should be after the blue line ends.
Response: The SDT fully expects that UFLS simulations will not need to be run beyond 60 seconds and that steady-state conditions between 59.3 and		

Organization	Yes or No	Question 9 Comment
60.7 Hz should be achived well before 60 seconds in most UFLS simulations.		
MidAmerican Energy	No	R3.3 should be deleted as it does not directly apply. If volts / hertz requirements remain, they should be consistent with the proper IEEE standards.
Response: The SDT has debated this question and has decided to retain the V/Hz requirement. The SDT is aware that there have been instances in UFLS studies where V/Hz has been seen as a risk to the tripping of generation and does not wish to leave a possible gap in reliability. Requirement R3, Part 3.3 is based on IEEE guidelines for setting V/Hz protection.		
Southern California Edison Company	No	SCE agrees with WECC's position that "This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided."
Response: The SDT believes that the degree of diversity in systems of various regions, particularly in the Eastern Interconnection, makes the determination of UFLS program design parameters an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design.		
Western Electricity Coordinating Council	No	The devices which implement UFLS must have discrete setpoints. The standards must establish criteria which is measurable. This type of criteria is only measurable by study or actual performance following a UFLS event. The planning criteria may use curves but these must be translated to a setpoint which can be verified.Each interconnection should establish discrete set points based upon stability and dynamic analysis. From discrete set points one can establish criteria which are measurable and performance based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC.The Standard needs to be very explicit that the curves are interconnection performance curves and not entity specific set points.What is the technical justification and correlation of the curves to the UFLS Plans, i.e. where did these curves come from?
Response: Each PC will need to devise UFLS Program design parameters that result in observance of the under and over frequency performance curves duing dynamic simulations of under frequency events and islands. The under and over frquency performance curves are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points.		

Organization	Yes or No	Question 9 Comment
The over and under frequency versus time performance curves for UFLS were determined to coordinate with the Generator under and over frequency tripping curves (which have been also coordinated with the PRC-024 SDT) and to set a margin between the UFLS and generator curves.		
South Carolina Electric and Gas	No	The graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curves data points.
Response: The SDT intends to document the data points for the curves.		
Exelon	No	The standard lacks guidance as to what the trip settings should be. It is not clear as to how Attachment 1 should be used and doesn't provide specific detail for under frequency set points. Exelon disagrees that R3.3 is easier to understand. Clarification is needed as to where the underfrequency set points are. Do all entities contribute equally to Attachment 1? There needs to be a standardized relationship between GO and TO/DP participation in obtaining the desired level of system performance. There should also be explicit criteria as to what the expectations are for each individual entity. It should be clear that all UFLS entities are to participate equally and that larger entities will not be expected to carry the burden for smaller entities.There should be some recognition in the standard that UFLS schemes currently exist and effort should be made to avoid needlessly changing relays or settings on many thousands of installations if some arbitrary and common set points were to be determined by the PC, thus causing needless expense. It is likely desireable to have slightly different settings for UFLS across a footprint so as to not create load changes that are too abrupt.The current practice of allowing contractual agreements between GOs and DPs for additional load shedding as a voluntary business decision, in the event that a unit owner doesn't comply with the unit trip settings should be addressed.
Response: The under and over frquency performance curves are solely for checking dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points. Requirement R3, Part 3.3 is based on IEEE guidelines for setting V/Hz protection. The Planning Coordinator, as part of the UFLS program design, will need to determine the participation level of the variously sized Transmission Owners and Distribution Providers. The SDT fully expects that existing UFLS programs will be sufficient to comply with the performance characterisitic curves and the the Planning Coordinators will not need to arbitrarily redetermine UFLS design parameters. The SDT has addressed the matter of GO versus TO/DP obligation for non-conforming generators and has decided that, for the likely small amount of non-conforming generation, that it should be a small burden, if any, to be spread across multiple TO sand DPs.		
FirstEnergy	No	We are concerned about the coordination between this UFLS SDT and the GV SDT. It will be difficult to approve and begin implementing the PRC-006-1 standard while the PRC-024-1 standard is still under development and scheduled for approval and implementation at a much later date. For these requirements to be adequately coordinated, the two standards need to be developed, balloted and implemented at the same

Organization	Yes or No	Question 9 Comment
		time. Alternatively, consider adding the following statement in the PRC-006-1 Implementation Plan: "The Effective Date and implementation of this PRC-006-1 standard requires coordination with standard PRC-024-1. Excluding requirement R1, the Effective Date of PRC-006 shall be the later of 1) the completion of the Implementation Plan for PRC-006 or 2) the completion of the Effective Date of the PRC-024-1 standard upon completion of its Implementation Plan."
Response: The UFLS (PRC-006) SDT has coordinated with the PRC-024 SDT. The SDT believes that even though the two standards are on different development schedules, there will not be miscoordination of the generator under and over frequency tripping curves, and the requirement on collection of data for the Planning Coordinators to obtain under and over frequency trip settings.		
Ameren	No	While this is an improvement over the previous draft, we still believe that Requirement R3.3, dealing with generator V/Hz limitations, should not be part of this standard.
Response: The SDT has debated this question and has decided to retain the V/Hz requirement. The SDT is aware that there have been instances in UFLS studies where V/Hz has been seen as a risk to the tripping of generation and does not wish to leave a possible gap in reliability.		
Duke Energy	Yes	
Entergy Services	Yes	
Indiana Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
MEAG Power	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
SERC Planning Standards Subcommittee	Yes	

Organization	Yes or No	Question 9 Comment
SERC SC UFLS Standard Drafting Team	Yes	
Southern Company Transmission	Yes	
SPP System Protection and Control Working Group	Yes	
Tennessee Valley Authority (TVA)	Yes	
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
Progress Energy - Carolinas	Yes	The curves added as Attachments 1 and 2 are excellent. However, it would be helpful if a footnote to the curves provided the values of the "transition points" or breakpoints of the curves. For example on Attachment 1, there appears to be transition point at 60 seconds/58.85 Hz, but it is difficult to read exactly.
Response: The SDT intends to document the data points for the curves.		
Wisconsin Electric Power Company (dba We Energies)	Yes	We agree with the concept of using the frequency time performance curves instead of discrete points. However, we would like the SDT to provide additional technical background on the methodology utilized to develop both the underfrequency and overfrequency time performance curves beyond what was discussed in the "Review of Technical Changes to Standard" section in the preface of the "Unofficial Comment Form."
Response: The over and under frequency versus time performance curves for UFLS were determined to coordinate with the Generator under and over frequency tripping curves (which have been also coordinated with the PRC-024 SDT) and to set a margin between the UFLS and generator curves. That is about all that can be said.		
NERC Staff	Yes	Yes, NERC staff supports the idea of better demonstrating coordination with the requirements proposed for PRC-024.
Response: Thank you for your comment.		

10. Besides replacing the discrete point thresholds in R7.1 and R7.2 (now parts 4.1 through 4.6 of Requirement R4) with curves, the SDT has clarified which generators with under- and underfrequency trip settings above and below these curves, respectively, must be included in the UFLS assessments in parts 4.1 through 4.6 of Requirement R4. The generators with non-conforming trip settings that must be included in the UFLS assessments are now limited to individual generating units greater than 20 MVA or generating plants/facilities greater than 75 MVA directly connected to the BES or any facility consisting of one or more units that are connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating. This clarification also makes parts 4.1 through 4.6 consistent with the generator size and connection thresholds in part 3.3.1 of Requirement R3. Do you agree with this clarification?

Summary Consideration: In response to the comments received, The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of Attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria.

Organization	Yes or No	Question 10 Comment
Southern California Edison Company		SCE is unsure of the ramifications of this change and, therefore, cannot confirm that we are in agreement with the change.
Response: Thank you for your comment		
Long Island Power Authority	No	
GDS Associates	No	- Not sure what is the intent of this classification of generating units >20MVA, generating facilities (two or more units) directly connected to BES >75MVA and generating facilities connected to a common bus to BES >75MVA- Are the requirements for the two
Response: The intent is to match the Statement of Compliance Registry Critiria.		
AECI	No	AECI can understand how we should be responsible for our own data, but the data we use for others is only as good as the data we receive. It seems like this standard also needs to apply to generator owners

Organization	Yes or No	Question 10 Comment
Response: The implementation plan and effective date language were changed to clarify that modeling of generator trip settings that do not conform with the curves of new Attachment 1 will only be effective after the Planning Coordinator receives the appropriate data in accordance with Project 2007-09 Generator Verification for draft Standard PRC-024 currently in development.		
Tri-State Generation & Transmission Assoc.	No	Comments: Underfrequency is an issue of load and generation balance. It does not make sense to make the distinction of whether or not a generator or generating facilities directly connect to the BES. The loss of sizable generation has the same impact on frequency regardless of what voltage it was connected at. The thresholds used in the standards are registration thresholds for the GO/GOP function. There is nothing that would prohibit a PC, TO or TOP from establishing interconnection requirements for smaller generators that require compliance with an UFLS program if it was important to reliable BES operation
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		
Exelon	No	Exelon feels that a table should be included with the curves. What was the source of the curves and the V/Hz requirements? The table seems to indicate that it is acceptable for the Eastern Interconnection to remain at 58.9 Hz for up to one minute. The data requirements for the assessment study should include additional data other than that for units out of compliance, i.e. all loads for the entire system as load is dropping.
Response: Formulas are now provided to supplement the curves. Requirement R4 has been modified to clarify that a steady state condition between 59.3 and 60.7 Hz is expected within 60 seconds, which is the intent of the vertical lines in the curves of Attachment 1. The source of the curves is to provide a margin between the curves developed in Project 2007-09 Generator Verification for draft Standard PRC-024. The V/Hz requirements are derived from IEEE standards. To clarify, units not in comformance with the curves are not necessarily out of compliance. Load modeling is an integral part of the dynamics database developed through the MOD standards.		
ReliabilityFirst Engineering Staff	No	It is not clear how the PC will determine which generating units are non-conforming as there is no requirement for the GO to provide this information in this standard. In a best case, it relies on the adoption of proposed standard PRC-024.
Response: The implementation plan and effective date language was changed to clarify that modeling of generator trip settings that do not conform with the curves of new Attachment 1 will only be effective after the Planning Coordinator receives the appropriate data in accordance with the Project 2007-09 Generator Verification for draft Standard PRC-024 currently in development.		

Organization	Yes or No	Question 10 Comment
NERC Staff	No	NERC staff disagrees with limiting the level of modeling in the assessments and feels that the modeling of generation should go beyond the 20 MVA and 75 MVA units as proposed. NERC staff believes that the UFLS design assessment should not be limited to modeling BES-connected resources. During a frequency excursion, all generation and frequency responsive devices "see" the excursion and react to it, regardless of size and location. Further, as penetration increases for similarly influential blocks of non-traditional resources (i.e., wind and solar farms) that have common underfrequency trip performance characteristics, it is essential that these dynamics and underfrequency trip characteristics should also be modeled and taken into account. This is not to say that each individual wind turbine or 500 kW generator must be modeled everywhere. However, when aggregate groupings of smaller units are known to be influential in dynamics analysis, or groupings of non-traditional resources with like frequency performance characteristics exist, it is essential that their influence be analyzed regardless of their voltage connection. The contribution to frequency response or common-mode tripping of such resources could mean the difference between a successful and unsuccessful UFLS system design.
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		
FirstEnergy	No	See our concerns in Question 9 about the coordination between this UFLS SDT and the GV SDT.
Response: The implementation plan and effective date language were changed to clarify that modeling of generator trip settings that do not conform with the curves of new Attachment 1 will only be effective after the Planning Coordinator receives the appropriate data in accordance with Project 2007-09 Generator Verification for draft Standard PRC-024 currently in development.		
Northeast Power Coordinating Council	No	Similar to the comment provided in response to Question 9, requirements 4.3 and 4.6 are simply restatements of requirements 4.2 and 4.5, respectively. Suggest that requirements 4.3 and 4.6 be eliminated, and that requirements 4.2 and 4.5 be rewritten to contain the language dealing with the applicability of composite facilities as defined in the Registry Criteria Section II.c.2.Additionally, this draft version of PRC-006 states in requirements 4.1 through 4.6 (as well as in requirements 3.3.1 through 3.3.3) that the assessment of non-conforming generator trip settings is limited to those generators generally defined by the Registry Criteria, rather than assuming that the Functional Entities shown in the Applicability Section of the Standard are further defined by the NERC Registry Criteria. This limitation is not necessarily valid for situations where any generator, regardless of size, is material to the reliability of the BES (Registry Criteria III.c.4). In particular during the development of a supporting Regional Standard it is quite possible that the amount of generation

Organization	Yes or No	Question 10 Comment
		whose non-conforming performance characteristics may be tolerated, (and thus eliminated from assessment consideration), will be very limited. In regions where a great preponderance of the total generation is comprised of smaller units the tolerance threshold for ignoring generation below a bright line value defined by PRC-006 may invalidate conclusions of the Regional UFLS Program assessments. These conclusions presently demonstrate that the Regional Program meets the broad performance characteristics and/or requirements of PRC-006. The PRC-006 SDT should be aware that those RSDTs developing Regional Standards will, based on necessity, assess the applicability of Functional Entities and to the degree that a materiality issue is raised will bring that issue before the Regional Entity. Regional Entities would be expected to confirm that reliability is at stake prior to the issuance of a Compliance Guidance Statement, or other communication tool. The RSDT expects that the reach of applicability governing the registration and compliance obligations of any such Functional Entity identified under the “material to the reliability of the bulk power system” clause of the Registry Criteria will be clearly defined in each Regional Standard.Generation facilities which do not meet the NERC generator registration criteria could avoid obligations to meet generator underfrequency and overfrequency trip requirements presented in the standard. Significant amounts of generation categorized as such could cumulatively jeopardize the performance of a UFLS program.Possible future trends in the development of generation could increase the amount of installed generation capacity that does not meet the NERC generator registration criteria. Such trends may include the development of renewable distributed generation that is not connected to the BES system.
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard’s implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		
IESO	No	The SDT should clarify the characteristics define where the generators are not permitted to trip rather than define where generators must trip. Correspondingly, it should be clarified for loads, the requirement defines the outer perimeter where UFLS loads must be tripped rather than to define where UFLS loads trip.The phrase; “directly connected to the BES” could be problematic. In the IESO-controlled grid most generators are connected to transmission system with a main output transformer. At many large generating stations, the low voltage bus of these MOTs where the generator is directly connected is not part of the BES while the high voltage bus is part of the BES. A restrictive interpretation of the present wording of the standard would limit applicability to only generating units captured under Â§R3.3.3, What interpretation of “directly connected” was intended by the SDT?Elements of this continent-wide standard are viewed by the IESO as a means to improve reliability not as a justification to weaken existing good practices. Does the STD support retaining existing more stringent standards (e.g. lower underfrequency thresholds and higher overfrequency thresholds or both) for generating units at the Regional or Planning Coordinator level? For example, the IESO-controlled

Organization	Yes or No	Question 10 Comment
		grid mandate generating units > 10 MW and generating facilities > 50 MW directly connected to the IESO-controlled grid to have generator protection set at a level such that they do not trip over the NPCC criteria for generator underfrequency curve. We need to seek the SDTs view on whether these conditions are sufficient to satisfy the intent of the PRC-006 standard.The response of the SDT to the earlier question (see below) concerning the need for overfrequency settings as part of this standard was not satisfactory as new requirements should have a strong motivation. Our Area experienced frequency excursions above those proposed in this standard without material adverse effects. Generation trips at these frequency levels in 2003 would have been inconsistent with the purpose of providing last resort system preservation measures. What are these referenced withstand capabilities and are they applicable to all types of units? What evidence is known to the SDT that units experience a significant loss of life due to the events on August 14, 2003 now that more than six years has passed? Why does the SDT believe overfrequency thresholds are necessary to fulfill the Purpose of this standard?[Response: Thank you for your comments. The SDT has developed the overfrequency characteristic in Requirement R6.3 to coordinate with the overfrequency trip setting limits proposed in PRC-024. The trip setting limits were developed by the Generator Verification SDT based on the withstand capabilities of generating units. The concern with operation of generating units at off-nominal frequency is the cumulative fatigue effect, so it is possible that generating units experienced significant loss of life on August 14, 2003 even if the adverse effects were not readily observable immediately after this event.]
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachement 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. **The term "directly connected" is intended in the same fashion as it is used in the Statement of Compliance Registry Criteria.** **Regional standards can be more restrictive than the national standard.**		
Bonneville Power Administration	No	Underfrequency is an issue of load to generation balance regardless of the voltage of the interconnection.
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of Attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		
Western Electricity Coordinating	No	Underfrequency is an issue of load to generation balance. It does not seem to make sense to make the distinction of whether or not a generator or generating facilities directly connect to the BES. The loss of

Organization	Yes or No	Question 10 Comment
Council		100MW of generation has the same impact on frequency if they are connected at 69kv or 500kv. The thresholds used in the standards are registration thresholds for the GO/GOP function and do not negate the impact of all generation on frequency response.
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of Attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan. As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		
Wisconsin Electric Power Company (dba We Energies)	No	We agree with the concept of using the PRC-024 generator underfrequency and overfrequency tripping curves instead of discrete points. In addition, we agree with the generator size and connection threshold clarification. However, we continue to believe that this standard places a burden on the UFLS Entity to shed additional load to make up for generators which do not conform to the PRC-006/PRC-024 curves. For example, if an independent power producer did not conform with the PRC-006/PRC-024 curves, it places a burden on the UFLS Entity to potentially have to shed additional load, up to the generator's rating, to make up for the non-conforming independent generator.
Response: Generator conformance with Project 2007-09 Generator Verification for draft Standard PRC-024 is beyond the scope of this standard. The SDT simply wants to recognize that some generators may not conform with that the resulting PRC-024 standard. No change made.		
Xcel Energy	No	We feel that our comment in the previous draft was not fully addressed. The dynamic simulation would need to include any small generators (<20MVA or <75MVA aggregate) that are not required to register, but together, could have a material impact on the BES. Additionally, it would need to be clear who is responsible for ensuring those material impacts are included in models/simulations.Distributed Generation (DG) is a growing concern that can have an impact on UFLS programs. Consider the need for adding that the assumptions related to DG be included in the R3 & R4 requirementsAdditionally, the Statement of Compliance Registry lists additional criteria for generator registration (i.e. black start, determined to be material to BPS). Shouldn't these be captured, or a more simple approach may be that all registered GOs be required to provide the requested data?
Response: The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of Attachment 1. In addition, many commenters have stated that the Planning Coordinator cannot model data that Generator Owners do not provide. Registered Generator Owners will provide the data through PRC-024 in accordance with that standard's implementation plan (Project 2007-09 Generator Verification). As a result of the small percentage of generators and the registration issues, the SDT decided to conform with theStatement of Compliance Registry Criteria. No change made.		

Organization	Yes or No	Question 10 Comment
Ameren	Yes	
American Transmission Co.	Yes	
Duke Energy	Yes	
Entergy Services	Yes	
IRC Standards Review Committee	Yes	
Manitoba Hydro	Yes	
MEAG Power	Yes	
MidAmerican Energy	Yes	
MRO's NERC Standards Review Subcommittee (NSRS)	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
SERC Planning Standards Subcommittee	Yes	
SERC SC UFLS Standard Drafting Team	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 10 Comment
Southern Company Transmission	Yes	
SPP System Protection and Control Working Group	Yes	
Tennessee Valley Authority (TVA)	Yes	
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
Progress Energy - Carolinas	Yes	We agree with respect to the Planning Coordinator simulation requirements for modeling as stated in R4. However, the UFLS standard has no requirement for the Generator Owners to provide this information. We have been told that this might be included in PRC-024 (currently under development). This should be a condition for approval of PRC-006. Additionally, the Generator Owners should be required to notify the PC of any Manual (i.e. operator actions) that would result in a trip above/below the specified generator curves of Attachments 1 and 2. It is recognized that manual operator actions would typically be later than the approximately 60 seconds or less simulation times that a PC would use. However, this information regarding manual trips would be necessary for appropriate planning.
Response: The implementation plan and effective date language was changed to clarify that modeling of generator trip settings that do not conform with the curves of new Attachment 1 will only be effective after the Planning Coordinator receives the appropriate data in accordance with the Project 2007-09 Generator Verification for standard PRC-024 currently in development.		
Indiana Municipal Power Agency	Yes	When looking at generation in the RFC region and by going with generating units that are specified in the current sub requirements of requirement 4, the Planning Coordinators will be capturing 96 PERCENT of the generation in the RFC region in their UFLS program and design assessment (data supplied by RFC). When looking at generation between 69kV and 100kV, only about 2 PERCENT increase is gained in this area by requiring these Generation Owners to report information (this is making the assumption that all these lower voltage units have UFLS relays). One has to question the value of this increase in requiring these generating units to report information when load is not being captured that accurately and the modeling has a certain percent error.In addition, NERC reporting requirements will have to apply to these generating units connected between 69kV and 100 kV which will force the NERC registration of these units. NERC compliance has made

Organization	Yes or No	Question 10 Comment
		the statement on several documented occasions that if a new Generator Owner goes on the NERC registry, then that entity will have to meet ALL the NERC Generator Owner standard requirements in a NERC and FERC audit, NOT just the NERC UFLS standard. This would be a case where a standard drives the NERC Registry and IMPA does not believe that reliability standards should drive and change the NERC Registry.
Response: Thank you for your comments.		

11. The SDT has replaced Requirement R4 appearing in the previous (second) draft of the standard. Requirement R4 required each group of Planning Coordinators to develop a procedure for coordinating with groups of Planning Coordinators in neighboring regions within an interconnection to identify and reach agreement on islands between its region and neighboring regions within the interconnection. Requirement R4 was removed because procedures for coordination do not directly support reliability. In version 3 of the draft standard, any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating this selection with neighboring regions (Requirement R1). The SDT has added a requirement for the Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by any one Planning Coordinator that encompasses more than one Planning Coordinator footprint (Requirement R5). Do you agree with this revision?

Summary Consideration: Many commenters expressed concern that Planning Coordinators cannot be expected to reach concurrence with another functional entity because it is outside their control to lead them to concurrence. The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on UFLS design assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. The ERO could be the final authority if it wishes to assume that role, otherwise there would be no final authority.

Organization	Yes or No	Question 11 Comment
FirstEnergy		We defer an opinion on this and leave it to the Planning Coordinators to decide if this requirement is feasible for them to implement.
GDS Associates	No	- Requirement R1 is quite unclear. Not sure how the criteria will be developed especially to include the interconnected adjacent sections of the BES. What if one of the adjacent entities does not agree to the criteria? Is that OK because the Planning Coordinator will no longer join groups so is no need to coordinate? **Response: The SDT believes that criteria for determination of islands should consider past events and system studies. The criteria may be as simple or complex as a Planning Coordinator desires. Since these criteria are used only to identify islands for UFLS assessments, adjacent entities do not need to agree.**
Tri-State Generation &	No	Comments: Elimination of Requirement R4 is acceptable; however, we believe that individual Planning Coordinators are not the entities to determine how islands should be formed. The current registration by

Organization	Yes or No	Question 11 Comment
Transmission Assoc.		numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. R2.3 seems to require each Planning Coordinator to ultimately divide into multiple islands or separate its transmission system from all other transmission systems as its own island. Part of the purpose of the UFLS program should be to mitigate the need to form islands by balancing total system loads and resources. It is an additional function to balance the loads and resources after the islands have been formed. We recommend eliminating R2.
Response: The SDT shares the concerns about Planning Coordinator registration. However, there are no other entities in the Functional Model that would be any better for this role. The problem is a registration issue and it is possible that some registered Planning Coordinators do not fit the Functional Model description very well. **Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. Those islands are to be used only in UFLS design assessments, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The intent of R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. There are no requirements to identify Planning Coordinator footprints as islands.** **UFLS cannot be expected to mitigate island formation. Most interconnections are large enough that a decline in frequency low enough to cause UFLS operations is highly unlikely unless the interconnection is broken into islands. Most UFLS operations are seen to occur following island formation. The SDT does not agree that balancing load and generation after island formation is an "additional" function of UFLS.** **R2 cannot be eliminated because islands must be identified in order to carry out the UFLS design assessments (R4).**		
Exelon	No	Exelons concern is that neighboring Planning Coordinators will be making requests and setting criteria for the local planning coordinators and associated UFLS entities. We do not agree with the text "any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating."
Response: Identification of islands (R2) is for UFLS design assessments only (R4), a requirement that applies only to Planning Coordinators. UFLS entities are not affected, nor will a Planning Coordinator need to make requests of them or set criteria for them as far as island identification is concerned. The SDT believes the quoted text is necessary due to the wide range of island determination criteria (R1) that may be forthcoming.		
Western Electricity Coordinating Council	No	From an enforcement standpoint there is concern that if Planning Coordinator may choose its islands, what then is the process for getting "Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by any one Planning Coordinator". Who is the final authority and how is the arrangement memorialized and notified?Also, please see comment to Question #8 concerning the role of the RA.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still		

Organization	Yes or No	Question 11 Comment
believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on UFLS design assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. The ERO could be the final authority if it wishes to assume that role, otherwise there would be no final authority.		
Bonneville Power Administration	No	If each Planning Coordinator may choose its islands, what then is the process for getting "Planning Coordinators to reach concurrence on the UFLS assessments for any islands identified by any one Planning Coordinator". Who is the final authority and how is the arrangement memorialized and notified? No clear definition of a Planning Coordinator footprint may impact adequate identification of and authority related to establishing concurrence.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on UFLS design assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others. The ERO could be the final authority if it wishes to assume that role, otherwise there would be no final authority. No requirement exists to identify Planning Coordinator footprints as islands.		
MidAmerican Energy	No	Instead of reaching concurrence, entities should be just required to inform adjacent interconnected NERC entities of the assessment results. Otherwise entities could potentially be held responsible for inaction of another planning coordinator. The language could be changed to be consistent with the language in EOP-003 R3, such as, "Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected (entities)".
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on UFLS design assessments. EOP-003, Requirement R3 is problematic in that there is no clear definition of "coordinate."		
Pepco Holdings, Inc. - Affiliates	No	It is difficult to see how this change corrected the described problem.
Response: It is a matter of ensuring that each requirement is linked to a reliability goal. The SDT believes that the change will be more acceptable to NERC and FERC approvers who are conscious of the need for each requirement to have a clear contribution to reliability.		
Tennessee Valley Authority (TVA)	No	R5 (and M5) is problematic in that it requires all affected PCs to reach concurrence. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard should require that one PC change its methods because another PC(s) does not agree with its methods, or agree that another method is acceptable that it finds a problem with. There needs to be a process in the event that PCs cannot reach concurrence. We recommend

Organization	Yes or No	Question 11 Comment
		that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island."
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others.		
American Transmission Co.	No	Replace the words "reach concurrence with" with "provide UFLS design assessment results to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion.		
Manitoba Hydro	No	Replace the words "reach concurrence with" with "provide UFLS design assessment results to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	Replace the words "reach concurrence with" with "provide UFLS design assessment results to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors.

Organization	Yes or No	Question 11 Comment
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion.		
Entergy Services	No	See above comment to questions #2 and #4.
SERC SC UFLS Standard Drafting Team	No	see above comment to questions #2 and #4.
Southern Company Transmission	No	see above comment to questions #2 and #4.
Progress Energy - Carolinas	No	See above comments to Questions #2 and #4.
Duke Energy	No	See comments above on questions #2 and #4.
IESO	No	The requirement to reach concurrence is outside of the capability of any single Planning Coordinator as concurrence requires at least two Planning Coordinators. The SDT should consider reformulating this requirement in terms of the actions it believes each Planning Coordinator must perform to reach concurrence with its fellow Planning Coordinators.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern.		
IRC Standards Review Committee	No	We agree with the need for Planning Coordinators in neighboring regions "to identify and reach agreement on islands between its region and neighboring regions". However, we believe new problems have been introduced. First, 2.3 under R2 is arbitrary and lacks any technical basis. There is no reason for splitting a island based on regional boundaries. Additionally, we are concerned that R1 may be viewed as an attempt to predict islands that may occur. Will a PC be held non-compliant if they predict incorrectly. There requirement needs to be clear that it is intended solely for the purpose of designing UFLS "islands".
Response: The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. Those islands are to be used in UFLS design assessments only, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. (The SDT agrees that there is no technical reason for designating Regional Entity footprints as islands.) **R1 does not require Planning Coordinators to predict islands that may occur in the future; it only requires criteria for island identification in order for the design assessments in R4 to be conducted. A Planning Coordinator cannot be judged non-compliant for failing to predict the future, but an**		

Organization	Yes or No	Question 11 Comment
unpredicted islanding event may be a reason to revisit the criteria.		
AECI	No	What if somebody else, with more stringent criteria than us, identifies us as an island and wants us to then conform to their more stringent criteria? It seems like if we did not identify them, the burden should not be placed on us. Also there seems to be potential for the actions of another utility to determine our compliance. **Response: The criteria required in R1 are for island identification only and are only to be applied by the Planning Coordinator that came up with them. No other Planning Coordinator is required to use or comply with another's R1 criteria. However, when the R4 assessment is performed, the other Planning Coordinator(s) in an island that spans two or more Planning Coordinator footprints will need to work with each other on the design assessments (R5) for those islands. (Note: R5 and R13 have been modified to address other commenter's concerns with the term "concurrence.")**
Ameren	Yes	
Indiana Municipal Power Agency	Yes	
Long Island Power Authority	Yes	
MEAG Power	Yes	
NERC Staff	Yes	
Northeast Power Coordinating Council	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC Planning Standards Subcommittee	Yes	

Organization	Yes or No	Question 11 Comment
South Carolina Electric and Gas	Yes	
SPP System Protection and Control Working Group	Yes	
Y-W Electric Association, Inc.	Yes	
Wisconsin Electric Power Company (dba We Energies)	Yes	Although we agree with the revision, we disagree with carrying forward the legacy concept of using an entire Regional Entity's footprint as an island. It is highly unlikely that the entire Regional Entity footprint would become an island. What is the technical justification for the continuation of the legacy concept of studying islands consisting of the entire Regional Entity's footprint? In addition, similar to the concurrence that the Planning Coordinators need to reach in R5, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: "The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets." Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R5, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: "The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission." Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly.
Response: The Regional Entity footprint islands are to be used in UFLS design assessments only, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. (The SDT agrees that there is no technical reason for designating Regional Entity footprints as islands.)		

Organization	Yes or No	Question 11 Comment
Several other commenters have expressed concern with use of the term "concurrence" and the SDT has modified R5 and R13 to address those concerns by removing "concurrence." The SDT agrees that UFLS Entities should have opportunity to provide input to the Planning Coordinator on what will be required of them. R14 has now been added to the standard and requires a peer review of a Planning Coordinator's design and schedule for implementation by the UFLS Entities. Hopefully, this addresses, at least in part, the commenter's suggestions.		
Xcel Energy	Yes	As long as the requirement as written still permits PCs to coordinate and select one or more islands between them to consider we are ok. Please clarify that R1 does not require that each PC must come up with their own unique island to consider.
Response: R1 only requires island identification criteria, not island identification, which is R2. Also, there are no requirements to identify Planning Coordinator footprints as islands. The only required islands are those portions of a system designed to island (Requirement R2, Part 2.2) and the Regional Entity footprint or interconnection islands (Requirement R2, Part 2.3).		
United Illuminating Company	Yes	Replace "reach" with "obtain".
Response: The SDT believes either term adequately conveys the intent and declines to make the change.		

12. The SDT added a Requirement R10 that requires each Transmission Owner to provide automatic switching of Elements in accordance with the UFLS program design. The SDT added this requirement in response to comments submitted in the second posting of the standard that indicated that automatic switching of Elements may be important as part of the UFLS program design. Do you agree with this requirement?

Summary Consideration:

Many commenters expressed concern that "switching of Elements" is not clear. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this 'providing' these elements is a function that would be performed by Transmission Owners.

Organization	Yes or No	Question 12 Comment
Western Electricity Coordinating Council		Requirement R10 is unclear and needs to be rewritten to assure the applicability.
Response: The SDT added this additional distinction for the purposes stated in Requirement R10. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Wisconsin Electric Power Company (dba We Energies)	No	Although we agree with the intent of this requirement, similar to the concurrence that the Planning Coordinators need to reach in R5 & R13, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: "The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission." Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R5 & R13, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: "The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic

Organization	Yes or No	Question 12 Comment
		tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets." Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly.
Response: The SDT understands your concern and has added Requirement R14, which requires notification of UFLS entities of the UFLS program design and schedule for application and a requirement to respond to feedback received.		
Tri-State Generation & Transmission Assoc.	No	Comments: Since "UFLS entity" already includes Transmission Owners, requirement R10 is unnecessary and "automatic switching of Elements" ought to be combined into R9 from R10 and then R10 can be deleted. **Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** UFLS programs should be developed by the Reliability Assurer, not individual Planning Coordinators. **Response: Our current understanding of the standards development process is that requirements written which apply to Reliability Assurer/Regional Reliability Organizations cannot be enforced the same way as other requirements. This standard is under development as a direct result of this particular issue and was identified as a part of a set of standards for having "fill in the blank" requirements. The SDT has crafted Requirements R5 and R13 in order to allow for and encourage coordination among PCs. This standard does not preclude the RRO/RA from performing this coordination function, but does not include a requirement for the RRO/RA for this purpose.**
American Transmission Co.	No	Consideration should be given to replacing "Transmission Owner" with "UFLS Entity" because the automatic switching of distribution Elements (e.g. capacitor banks) may be more effective and practical UFLS design than restricting the scope of the requirement to just transmission Elements.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
FirstEnergy	No	FE questions the need for this requirement and the Applicability Section item 4.3. FE asks that the SDT provide some examples of the reliability need related to frequency control for this requirement. If high voltage and automatic capacitor bank switching is the issue we don't believe that rises to a need as a reliability requirement within a UFLS standard. Voltage control should remain a separate issue from controlling frequency that this standard aims to address. Load shedding associated with UFLS is just one of many reasons why proper voltage control - through automatic Element switching of a capacitor bank - would be

Organization	Yes or No	Question 12 Comment
		needed for the transmission system. If there are other technical reasons for this requirement please clarify.
Response: Some members of the UFLS SDT have experience with these types of component switching which are integral to certain UFLS schemes where sudden loss of load can quickly negate the necessity of these reactive compensation devices and, in some instances, transmission lines. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Tennessee Valley Authority (TVA)	No	It is not clear what is included in automatic switching. If it is the automatic switching of Elements for the sake of removing load, it would appear to be covered under R9. **Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** R10 refers to "Elements" and M10 refers to "Facilities".In both R9 and R10, suggest replacing the word "provide" with "implement". **Respones: The SDT agrees and has edited R10 and M10 to amend this discrepancy.**
SERC Planning Standards Subcommittee	No	It is not clear what is included in automatic switching. This requirement is so vague that it does not appear to add anything in addition to the UFLS program design that it is intended to address. It appears that anything that R10 may be designed to address is already covered by R9.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Ameren	No	It is not clear what should be included in automatic switching. This requirement is vague. It appears that Requirement R9 would address anything that Requirement R10 would have been intended to cover.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Northeast Power Coordinating Council	No	Limiting applicability to only the TO limits the thrust of this requirement in cases where other FM entities are responsible for switching of elements that support the UFLS program. The Drafting Team should consider modifying R4 to include a requirement to model any automatically switched elements related to a UFLS program.The Drafting Team should consider a requirement to inform the Planning Coordinator of the implementation of UFLS relay inhibit schemes (e.g. voltage inhibit) and any associated parameters.

Organization	Yes or No	Question 12 Comment
		Knowledge of such information would be vital to the Planning Coordinator when assessing the performance of a UFLS program.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Bonneville Power Administration	No	Requirement R10 is unclear and needs to be rewritten to clearly address the applicability.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Southern California Edison Company	No	SCE would hope that the drafting team provides additional clarification on this requirement, as we are unsure of what the team intends by "automatic switching of Elements".
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	The NSRS basically agrees with the concept that owners of automatic switching elements provide control in accordance with the UFLS program requirements. Therefore, [1] consideration should be given to replacing "Transmission Owner" with "UFLS entity" because the automatic switching of distribution Elements (e.g. capacitor banks) may be more effective and practical in UFLS program design than restricting the scope of the requirement to just transmission Elements.[2] And consider replacing "UFLS program" with "UFLS program requirements".
Response: The SDT added this additional distinction for the purposes stated in Requirement R10. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
IESO	No	The STD may wish to consider reworking R10 in a format that matches changes to applicability. Within the IESO footprint, low voltage capacitors may be switched as part of the ULFS program. In some cases, these capacitors would below to Distribution Providers rather than Transmission Owners. "Each UFLS entity shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint."
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to		

Organization	Yes or No	Question 12 Comment
control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Xcel Energy	No	We have concerns that R9 & R10 provide the Authority of a PC to direct investment and actions to another entity, without the agreement from that entity. Thus we feel that R5 should be modified to require concurrence from each affected UFLS Entity as well.
Response: The SDT understands your concern and has added Requirement R14, which requires notification of UFLS entities of the UFLS program design and schedule for application and a requirement to respond to feedback received.		
Duke Energy	No	We question whether/how this requirement would apply to a Transmission Owner who has UFLS on distribution circuits. It's unclear to us how this would be determined by the Planning Coordinator.
Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
MEAG Power	No	What are automatic switching of elements? Does it mean that the TO needs to switch capacitor banks, or does it refer to the breakers equipped with UF relays? If it is referring to capacitor banks, is this applicable near major generation busses?
Response: The SDT has clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.		
Y-W Electric Association, Inc.	No	Y-WEA is concerned about this requirement in that it seems to require the installation of facilities rather than just relays. 16 USC 824o (a)(3) gives NERC the authority to regulate existing facilities and planned additions or modifications to those facilities, not to prompt or require modifications or additions to the existing facilities. This proposed requirement seems to run afoul of this section of the USC.
Response: The SDT has added Requirement R14, which requires notification of UFLS entities of the UFLS program design and schedule for application and a requirement to respond to feedback received. **The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.**		
AECI	Yes	

Organization	Yes or No	Question 12 Comment
Exelon	Yes	
Illinois Municipal Electric Agency	Yes	
Indiana Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
Long Island Power Authority	Yes	
Manitoba Hydro	Yes	
MidAmerican Energy	Yes	
NERC Staff	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
ReliabilityFirst Engineering Staff	Yes	
South Carolina Electric and Gas	Yes	
SPP System Protection and	Yes	

Organization	Yes or No	Question 12 Comment
Control Working Group		
United Illuminating Company	Yes	
Entergy Services	Yes	It is not clear what is included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching of a capacitor to avoid overvoltage). **Response: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** R10 refers to "Elements" and M10 refers to "Facilities.", please change one of the references for consistency.In both R9 and R10, replace the word "provide" with "implement." **Respond: The SDT agrees and has edited R10 and M10 to amend this discrepancy.**
SERC SC UFLS Standard Drafting Team	Yes	It is not clear what is included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching of a capacitor to avoid overvoltage). **Respond: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** R10 refers to "Elements" and M10 refers to "Facilities."In both R9 and R10, replace the word "provide" with "implement." **Respond: The SDT agrees and has edited R10 and M10 to amend this discrepancy.**
Southern Company Transmission	Yes	It is not clear what is included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching of a capacitor to avoid overvoltage). **Respond: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** R10 refers to "Elements" and M10 refers to "Facilities."In both R9 and R10, replace the word "provide" with "implement." **Respond: The SDT agrees and has edited R10 and M10 to amend this discrepancy.**

Organization	Yes or No	Question 12 Comment
Progress Energy - Carolinas	Yes	It is not clear what would be included in automatic switching. Illustrative examples would be helpful to clarify what is meant (e.g. automatic switching out of a capacitor bank to avoid overvoltage when designed as part of the UFLS scheme). **Respond: The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** R10 refers to "Elements" and M10 refers to "Facilities". Revise to make consistent.In both R9 and R10, replace the word "provide" with "implement." **Respond: The SDT agrees and has edited R10 and M10 to amend this discrepancy.**

13. The SDT added new Requirements, R11 through R13. Requirement R11 requires each Planning Coordinator, in whose footprint a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, to conduct and document an assessment of the performance of UFLS equipment and the UFLS program effectiveness within one year of event actuation. Requirement R12 requires Planning Coordinators, in whose islanding event assessments (per R11) UFLS program deficiencies are identified, to conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. Lastly, Requirement R13 requires Planning Coordinators, in whose footprint a BES islanding event affecting multiple Planning Coordinator footprints and resulting in system frequency excursions below the initializing set points of the UFLS program, to reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment is complete. These requirements were added to provide continuity on the requirement to assess UFLS program effectiveness for events since there is a similar requirement (with different applicable entities) currently in PRC-009-0, but PRC-009-0 is to be retired on approval of this standard. Do you agree with the addition of these requirements?

Summary Consideration:

Several commenters indicated that the requirement for the event assessment should contain a lower threshold. However, PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.

Several comments questioned whether the Planning Coordinator is the appropriate entity for UFLS activities. The SDT believes the Planning Coordinator, having a wide-area view and the necessary technical skills, is the proper entity to oversee the design and implementation of UFLS. There is also wide industry support for the Planning Coordinator as the proper entity for UFLS. The Reliability Assurer has a very limited scope of activity in the Functional Model and is not a user, owner or operator of the BES.

Organization	Yes or No	Question 13 Comment
Western Electricity Coordinating Council		From and enforcement standpoint whom is the final authority and how are arrangements memorialized and notified? In addition these requirements address issues which indicate a failure or inadequacy of the initial required planning process and appear overall to allow PC to establish a program based on inadequate study and then fix it after an event which proves the program was inadequate. All without any violation of standard.
Response: (Note: R5 and R13 have been modified to address other commenter's concerns with the term "concurrence.") For R13, the ERO could be the final authority if it wishes to assume that role, otherwise there would be no final authority.		

Organization	Yes or No	Question 13 Comment
Whether a UFLS plan or design is able to secure or would fail to secure a system or island during an underfrequency event is something that cannot be predicted ahead of time. This in no way suggests that the design and assessment requirements (R3 and R4) are somehow inadequate. 100 percent reliability cannot realistically be assured; it is possible that an underfrequency event may occur that exceeds the UFLS design parameters, but that is an acceptable risk. R12 is included so that, should an event occur where a UFLS design failed to secure a system or was otherwise deficient, a process to at least consider improvements or enhancements would be followed.		
FirstEnergy		We defer an opinion on this and leave it to the Planning Coordinators to decide if this requirement is feasible for them to implement.
GDS Associates	No	- Requirement R11. The one year deadline it seem very long. There can be multiple events before assessment is due. - Requirement R12. Same comment regarding the assessment due date. **Response: Some events can be very complicated and take much time to figure out. The SDT would rather allow too much time, rather than not enough time.**
American Transmission Co.	No	1. For R11, replace “Each Planning Coordinator, in whose footprint . . . to evaluate” with “When a disturbance event occurs in a Planning Coordinator’s footprint that involves automatic UFLS program operation or frequency excursions should have activated UFLS program operation, and a final disturbance report is required per EOP-004, each Planning Coordinator shall evaluate within one year of the disturbance event:”. 2. Either part of or after R11, there should be a requirement that “Each Planning Coordinator shall provide a preliminary event assessment report to the other Planning Coordinators who must conduct an assessment of the event for review at least 90 days before finalizing the event assessment report.3. For R13, replace “in whose footprint . . .on the event assessment result” with “that conducts an UFLS design assessment (per R12) for islands where other Planning Coordinators have design assessment responsibilities shall provide a preliminary design assessment report to those Planning Coordinators for review at least 90 days before finalizing the design assessment report. The reference to the event assessment report should be part of R11. The qualification of “event affecting multiple Planning Coordinators” is too vague and could be interpreted and categorized differently by various entities and auditors
Response: 1. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. **2, 3. These suggestions are more administrative to facilitate agreement. Requirements should try to spell out the reliability objective to be achived and less how a reliability objective may be achieved.**		
Manitoba Hydro	No	1. For R11, replace “Each Planning Coordinator, in whose footprint . . . to evaluate” with “When a disturbance event occurs in a Planning Coordinator’s footprint that involves automatic UFLS program operation or frequency excursions should have activated UFLS program operation, and a final disturbance report is

Organization	Yes or No	Question 13 Comment
		required per EOP-004, each Planning Coordinator shall evaluate within one year of the disturbance event:". 2. We have concerns about specifying that the evaluation must be complete within one year we know that some historical studies of events that included UFLS took longer than one year [e.g., three years] to complete. Therefore, we would prefer a more flexible wording, a longer time frame to be used in this requirement. Perhaps the requirement could stipulate that the evaluation must begin within 6 months and be completed within the schedule set by the investigative team. 3. For R13, replace "in whose footprint . . .on the event assessment result" with "that conducts an UFLS design assessment (per R12) for islands where other Planning Coordinators have design assessment responsibilities shall provide a design assessment report to those Planning Coordinators." The reference to the event assessment report should be part of R11. The qualification of "event affecting multiple Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors.
Response: 1. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. **2. One year ahould be sufficient for the majority of events.** **3. This suggestion is more administrative to facilitate agreement. Requirements should try to spell out the reliability objective to be achived and less how a reliability objective may be achieved.**		
MRO's NERC Standards Review Subcommittee (NSRS)	No	1. For R11, replace "Each Planning Coordinator, in whose footprint . . . to evaluate" with "When a disturbance event occurs in a Planning Coordinator's footprint that involves automatic UFLS program operation or frequency excursions that should have activated UFLS program operation, and a final disturbance report is required per EOP-004, each Planning Coordinator shall evaluate within one year of the disturbance event:".2. We have concerns about specifying that the evaluation must be complete within one year we know that some historical studies of events that included UFLS took longer than one year [e.g., three years] to complete. Therefore, we would prefer a more flexible wording, a longer time frame to be used in this requirement. Perhaps the requirement could stipulate that the evaluation must begin within 6 months and be completed within the schedule set by the investigative team. 3. For R13, replace "in whose footprint . . .on the event assessment result" with "that conducts an UFLS design assessment (per R12) for islands where other Planning Coordinators have design assessment responsibilities shall provide a design assessment report to those Planning Coordinators." The reference to the event assessment report should be part of R11. The qualification of "event affecting multiple Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors. 4. R11.2, change the wording to replace "effectiveness of the UFLS program" with "conformance with UFLS program design". Because no UFLS program can be designed to be effective for all possible contingency scenarios but should be effective for the contingency

Organization	Yes or No	Question 13 Comment
		scenarios for which it was designed.
Response: 1. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. **2, 3. These suggestions are more administrative to facilitate agreement. Requirements should try to spell out the reliability objective to be achived and less "how" a reliability objective may be achieved.** **4. The SDT disagrees because this change reduces the scope of the assessment. Conformance with UFLS program design is a subpart of effectivenss of UFLS program. The overal effectiveness is still of interest even if an event is beyond design capability.**		
Wisconsin Electric Power Company (dba We Energies)	No	Although we agree with the intent of these requirements, the assessment required in R11 & R13 should only be completed for significant UFLS events. Similarly, the significant event concept should be applied to the islanding criteria in R1. In fact, the SDT mentions this concept in the "Review of Technical Changes to Standard" section in the preface of the "Unofficial Comment Form." In the aforementioned section, the SDT uses a 500 MW qualifier which states "...resulting in 500 MW or greater of..." for R11 & R13 but the qualifier was not added to version 3 of the draft standard. Instead of an arbitrary 500 MW qualifier, the SDT should define islands of significance by looking at the transmission interface that feeds the potential island area and what is the IROL (Interconnection Reliability Operating Limit) for that transmission interface. If the amount of load in the island area is below the IROL limit, the island would not be considered as a basis in the UFLS program design and excluded from a UFLS assessment following a UFLS event. This significant event concept based on IROL should be included in the islanding criteria in R1 and the assessment requirements of R11 and R13. Similar to the concurrence that the Planning Coordinators need to reach in R13, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: "The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets." Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R13, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of

Organization	Yes or No	Question 13 Comment
		Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: "The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission." Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly.
Response: The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. **The Regional Entity footprint islands are to be used in UFLS design assessments only, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. The intent of R2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. (The SDT agrees that there is no technical reason for designating Regional Entity footprints as islands.)** **Several other commenters have expressed concern with use of the term "concurrence" and the SDT has modified R5 and R13 to address those concerns by removing "concurrence." The SDT agrees that UFLS Entities should have opportunity to provide input to the Planning Coordinator on what will be required of them. R14 has now been added to the standard and requires a peer review of a Planning Coordinator's design and schedule for implementation by the UFLS Entities. Hopefully, this addresses, at least in part, the commenter's suggestions.**		
Entergy Services	No	As noted in our response to question #4 above, we recommend elimination of R13.The 500 MW limitation discussed in the background section should be included in R11. There is no need to evaluate smaller islanding events.
Response: See SDT response to Q4 comment. The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
SERC SC UFLS Standard Drafting Team	No	As noted in our response to question #4 above, we recommend elimination of R13.The 500 MW limitation discussed in the background section should be included in R11. There is no need to evaluate smaller islanding events.

Organization	Yes or No	Question 13 Comment
Response: See SDT response to Q4 comment. The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
Southern Company Transmission	No	As noted in our response to question #4 above, we recommend elimination of R13.The 500 MW limitation discussed in the background section should be included in R11. There is no need to evaluate smaller islanding events.
Response: See SDT response to Q4 comment. The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
Progress Energy - Carolinas	No	As per our comment to Question #4, we recommend R13 be deleted. The 500 MW limitation discussed in the background section of the comment form should be included in R11. There is no need to require assessments for smaller islanding events.
Response: See SDT response to Q4 comment. The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
Northeast Power Coordinating Council	No	At present, the language in the implementation plan describes a one year phase in for compliance intended to provide Planning Coordinators sufficient time to develop or modify UFLS programs and to establish a schedule for implementation.NPCC has already developed an implementation plan. It must be noted that the NPCC implementation plan is a six year plan and the final language of the NERC implementation plan with regard to the overall approved term will have be closely monitored.
Response: Thank you for your comment. The schedule for implementation by UFLS Entities is at the discretion on the Planning Coordinator and is not set by the standard.		
MidAmerican Energy	No	MidAmerican notes that past under frequency event analyses are complex and that the minimum time frames for analysis and implementation should be increased to at least 2 years and exception requests for additional time should be allowed.
Response: One year ahould be sufficient for the majority of events.		
Duke Energy	No	R11 and R12 are okay, but R13 contains the problematic requirement to “reach concurrence”, as discussed in our responses to questions #2 and #4 above. Perhaps R13 could be revised to require affected Planning Coordinators to share event assessment results and respond to technical questions/comments within a

Organization	Yes or No	Question 13 Comment
		prescribed time period.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern		
AECI	No	R13 seems unreasonable. If we do everything in our power to concur with another planning coordinator and they do not concur, our compliance is then determined by somebody else's actions.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern.		
Bonneville Power Administration	No	Requirement R13 needs to rewritten because language is unclear, i.e. what is meant by "of UFLS actuated loss of load"?
Response: R13 was revised and the phrase, ". . . of UFLS actuated loss of load occurs. . ." was deleted.		
IESO	No	Small islands and frequency excursions below the initializing set points can result from recognized contingencies. In some cases, the island formed will be so small as to provide no meaningful evaluation for UFLS program effectiveness. Some additional guidance from the SDT is needed to define the nature of events that are intended to trigger an evaluation under R11.
Response: PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
Ameren	No	The intention of R13 is good but a provision should be provided for each Planning Coordinator to comply with R11 in the event that it is not feasible to satisfy R13 within the one year assessment period. The Planning Coordinator's compliance with R11 should not be dependent on actions by others.The 500 MW limitation discussed in the background section should be included in R11 to make sure this thought is not lost if/when the standard becomes effective. There is no need to evaluate smaller islanding events.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The 500 MW qualifier was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
SERC Planning Standards Subcommittee	No	The intention of R13 is good but a provision should be provided for each Planning Coordinator to comply with R11 in the event that R13 is not satisfied within the one year assessment period specified in R11. A Planning Coordinator's compliance with R11 should not be dependent on actions by other Planning Coordinators.The 500 MW limitation discussed in the background section should be included in R11. There is no need to

Organization	Yes or No	Question 13 Comment
		evaluate smaller islanding events.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The 500 MW qualifier was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.		
Tennessee Valley Authority (TVA)	No	TVA agrees with the intent of transitioning post-event analysis from PRC-009-0 to the proposed PRC-006-1 standard, but has the following comments:R11: The “500 MW or greater” threshold included in the background information should be included in R11.R13/M13: TVA has similar concerns with the requirement to reach concurrence with other affected PCs that are expressed in response to Question 11 for R5/M5. We recommend elimination of R13/M13, or the addition of language that would eliminate the compliance of a PC having dependency on the concurrence of one or more other PCs.
Response: The 500 MW qualifier was an item of earlier SDT discussion and inadvertantly was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern.		
Xcel Energy	No	We don’t believe these should be limited to islanding events. Suggest rewording to indicate that “events resulting in frequency excursions below initializing set points of the UFLS program, or actuate automatic switching or tripping shall ...”
Response: The purpose of automatic switching of capacitor bands, Tranmission Lines and reactors is to control voltage as a result of under frequency load shedding. This requirement was added to assist in recovery as a result of under-frequency load shedding.		
Exelon	Yes	
Indiana Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
Long Island Power Authority	Yes	
MEAG Power	Yes	

Organization	Yes or No	Question 13 Comment
NERC Staff	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
ReliabilityFirst Engineering Staff	Yes	
South Carolina Electric and Gas	Yes	
SPP System Protection and Control Working Group	Yes	
United Illuminating Company	Yes	
Y-W Electric Association, Inc.	Yes	
Tri-State Generation & Transmission Assoc.	Yes	Comments: The concept is correct but we believe an individual Planning Coordinator is the wrong entity to assess the operation and revise it. There is no clear jurisdiction for a PC. This should remain the responsibility of the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area.Why is “of UFLS actuated loss of load occurs” included in R13 but not in R11? It does not seem to add any information but does seem to unnecessarily complicate the requirement. This again seems like an argument for having the Regional Assurer involved because concurrence between Planning Coordinators is required. The language is unclear in R13 and should be re-written.
Response: The SDT believes the Planning Coordinator, having a wide-area view and the necessary technical skills, is the proper entity to oversee the design and implementation of UFLS. There is also wide industry support for the Planning Coordinator as the proper entity for UFLS. The Reliability Assurer has a very limited scope of activity in the Functional Model and is not a user, owner or operator of the BES. **R13 was revised and the phrase, “. . . of UFLS actuated loss of load occurs. . .” was deleted.**		

14. The industry identified a need for a variance for the Québec Interconnection within NPCC to address the physical characteristics of the Québec system. This variance allows frequency decline to be arrested at a lower threshold and higher frequency overshoot without jeopardizing reliability because the installed generation in the Québec Interconnection is 98 percent hydraulic. The variance also establishes a different capacity threshold for the generating units for which underfrequency and overfrequency trip settings must be modeled to address concerns that by 2020, 10 percent of the installed capacity in Québec may be located at plants less than 75 MVA. The SDT has proposed the variance that meets the needs of the Québec interconnection in the third draft of the standard. In particular SDT developed the variance to Requirement R3 parts 3.1 and 3.2 and Requirement R4 parts 4.1 through 4.6. The variance to these requirements reference separate under and overfrequency curves included as attachments 1A and 2A to the standard. Do you agree with this Variance?

Summary Consideration:

The standard drafting team received support for the variance. Several un-related comments were received and the standard drafting team provided responses to those comments below.

Organization	Yes or No	Question 14 Comment
MEAG Power		No comment.
Xcel Energy		No comments
Western Electricity Coordinating Council		The standard and performance requirements should reflect the individual interconnections and not a continent wide standard allowing for the uniqueness of each interconnection to be addressed similar to Hydro Quebec's variance.There is not a place to provide a response to question 15 from the unofficial word verison, so it is being provided here.Q 15While the concern for loss of additional generation units because of their V/Hz protection schemes is understood, the bases for the 1.18pu and 1.1pu values are not evident and may not be technically supportable when compared against actual protection settings or allowable post-contingency voltage bands. Further, V/Hz protection settings vary across the system and it is unlikely adherence to this requirement will impact reliability. It will only increase dynamic analysis requirements. We recommend removing R3.3.
Response: The V/Hz is derived from IEEE standards. The standard allows the Planning Corodinators within a region to work together to develop a		

Organization	Yes or No	Question 14 Comment
program accounting for the characteristics of each Interconnection or region. No change made.		
Tri-State Generation & Transmission Assoc.	No	Comments: The standard should adequately recognize the performance characteristics of different type of generation and a variance should not be required. Faster acting and greater inertia systems should be allowed the operating margins appropriate to their systems. Real differences exist between interconnections. The standard and its performance requirements should reflect this fact. This would allow for the uniqueness of each interconnection to be addressed similar to Hydro Quebec's variance.
Response: The standard allows the Planning Coordinators within a region to work together to develop a program accounting for the characteristics of each Interconnection or region. No change made.		
Bonneville Power Administration	No	The standard and performance requirements should reflect the individual interconnections and not a continent-wide standard. This would allow for the uniqueness of each interconnection to be addressed similar to Hydro Quebec's variance.Other Comments:While the concern for loss of additional generation units because of their V/Hz protection schemes is understood, the bases for the 1.18pu and 1.1pu values are not evident and may not be technically supportable when compared against actual protection settings or allowable post-contingency voltage bands. Further, V/Hz protection settings vary across the system and it is unlikely adherence to this requirement will impact reliability. It will only increase dynamic analysis requirements. We recommend removing R3.3.
Response: The standard allows the Planning Coordinators within a region to work together to develop a program accounting for the characteristics of each Interconnection or region. No change made.		
Ameren	Yes	
American Transmission Co.	Yes	
Entergy Services	Yes	
Exelon	Yes	
FirstEnergy	Yes	
IESO	Yes	

Organization	Yes or No	Question 14 Comment
Indiana Municipal Power Agency	Yes	
IRC Standards Review Committee	Yes	
Long Island Power Authority	Yes	
MidAmerican Energy	Yes	
MRO's NERC Standards Review Subcommittee (NSRS)	Yes	
NERC Staff	Yes	
Northeast Power Coordinating Council	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Progress Energy - Carolinas	Yes	
ReliabilityFirst Engineering Staff	Yes	
SERC SC UFLS Standard Drafting Team	Yes	
South Carolina Electric and Gas	Yes	
Southern Company Transmission	Yes	

Organization	Yes or No	Question 14 Comment
SPP System Protection and Control Working Group	Yes	
Tennessee Valley Authority (TVA)	Yes	
United Illuminating Company	Yes	
Wisconsin Electric Power Company (dba We Energies)	Yes	
Y-W Electric Association, Inc.	Yes	
SERC Planning Standards Subcommittee	Yes	The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officiers.
Response: Thank you		
Manitoba Hydro	Yes	We are contemplating a variance. However, this variance must apply to other areas such as Manitoba Interconnection within MRO to address the physical characteristics of the Manitoba system. Manitoba system physical characteristics are very much similar to QuÃ©bec system. More than 90 % of installed generation in the Manitoba Interconnection is hydraulic. Manitoba Hydro may provide modifications to attachments 1B and 2B that would be applicable for Manitoba hydro area and cover UFLS program for an imbalance of more than 25%.
Response: Thank you. Variances requested will be reviewed.		
The California ISO	Yes	We request a WECC Regional variance for WECC to use its own set-points that are applicable to WECC members. (similar to what Hydro Quebec has done.)
Response: This comment process is not the method to request a variance. Variances requested will be reviewed.		

Consideration of Comments on Initial Ballot — Project 2007-01 — Underfrequency Load Shedding — Non-binding poll for VRF and VSLs
Date of Non-binding Poll: July 8-17, 2010

Summary Consideration: Many of the comments received indicated that until the SDT addressed the issues with the proposed standard support could not be offered for the proposed VRFs and VSLs. The SDT has made conforming changes to the proposed standards based on comments received during the posting and ballot of the standards that address many of the concerns. In addition, the SDT has addressed many of the suggested revisions to the VSLs proposed by commenters.

Many comments received in this poll indicated concern with the requirement to reach concurrence with other Planning Coordinators. The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen at 609-452-8060 or at Herb.Schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	1. R5 and R13 require that both or all the PC's reach concurrence on the assessment of the UFLS performance in an island. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. A standard should not require that one PC has to agree with another PC. 2. **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. There may need to be some give and take among Coordinators with recognition that no one methodology or margin criterion is right to the exclusion of all others.** R11 needs to have a MW size threshold for requiring the assessment of an UFLS event. As written, this requirement could require an assessment of an event where a breaker opened on a radial 115 kV line which had an 8 MW generator and 15 MW of load on the feeder.
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	
Gwen S Frazier	Gulf Power Company	3	Negative	
Don Horsley	Mississippi Power	3	Negative	

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				Such a small event has no consequence to the reliability of the BES. A MW threshold of 500 MW would be appropriate. **Response: PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. The existing standard PRC-009, which this standard is intended to replace, currently requires that an assessment be performed for all events regardless of size. The SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the requirement the same or better than what exists today.** 3. Miscellaneous improvements required to wording of R5, M5, and several VSL's. **Response: The SDT provided a detailed response to the suggested improvements in the Consideration of Comments report for the formal comment period conducted in June-July, 2010.**
Response:				
Jason Shaver	American Transmission Company, LLC	1	Negative	Although Draft 3 contains many significant improvements, there are still too many important issues that are not adequately addressed.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Mel Jensen	APS	5	Negative	Based on the negative vote on Project 2007-01 Underfrequency Load Shedding, the proposed VRFs and VSLs are rejected until the concerns with the proposed standard are addressed.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Robert D Smith	Arizona Public Service Co.	1	Negative	Based on WECC's 7/15/10 Position Paper for the ballot of Project 2007-01 - UFLS. "In addition to the ballot of PRC-006-1, a non-binding poll of the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is being conducted. Because of the recommended NO vote, members of the Underfrequency Load Shedding ballot pool are encouraged to reject the proposed VRFs and VSLs until such time that the concerns with the proposed standard are addressed".
Thomas R. Glock	Arizona Public Service Co.	3	Negative	
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	BC Hydro will not support the VRF and VSL document until such time as BC Hydro can support the UFLS standard Project 2007-01

Voter	Entity	Segment	Vote	Comment
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
John C. Collins	Platte River Power Authority	1	Negative	Because of the recommended NO vote on the standard, it would not make sense to approve the proposed VRFs and VSLs until such time the requirements of the standard are clarified.
Terry L Baker	Platte River Power Authority	3	Negative	
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	Can't vote yes on the VRF and VSL until the standard is at a point where I can vote yes for it.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	Comments associated with the negative vote are contained in the Project 2007-01 comment form submitted by TVA
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	Comments provided in comment form
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Russell A Noble	Cowlitz County PUD	3	Negative	Cowlitz cannot vote affirmative until it can also vote affirmative on the Standard as a whole.
Rick Syring	Cowlitz County PUD	4	Negative	
Bob Essex	Cowlitz County PUD	5	Negative	
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				

Voter	Entity	Segment	Vote	Comment
Joseph O'Brien	Northern Indiana Public Service Co.	6	Negative	EOP-003 It appears that there is, and always was, confusion with the use of "or" in EOP-003. For example in R5 the TOP or the BA shall implement a plan in steps. What if the TOP does this and the BA does not; is there a violation of the standard? This is not clear to me especially with BA/LBA JROs now in play. This could end up with "finger pointing" between the TOP and BA at audit time. In R4 it now states that voltage rate/level and power flow need to be considered when designing an automatic load shedding scheme. We have UFLS only and this appears to be a new requirement for us which may be a concern. Was that the intent? What does insufficient generation mean? Because the TOP or the BA shall shed customer load at this point according to R1. Does this mean when you're stuck at 59.98 Hz you should shed load, after all remedial steps? PRC-006 There are 22 pages of material to review and vote on; this is a bit overwhelming. Why not just work on the requirements first and leave the measurements for a later draft. It's too much. Applicability 4.3 is already covered in 4.2 There are Planning Coordinators within Planning Coordinators which makes it unclear who is responsible for all this compliance. It's not clear at all how a PC is to determine where islands are likely to occur.
Response: There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1. **The drafting team did not make any modifications to EOP-003, Requirement R4. This is an existing requirement, not something new.** **The SDT added this additional distinction for the purposes stated in Requirement R10. The SDT has further clarified R10 to include the "automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under frequency load shedding" and believes this is a function which would be performed by Transmission Owners.** **The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.** **A Planning Coordinator must identify at least one island to be used as the basis for the R4 UFLS design assessment. However, this does not mean that islands must be identified from a Planning Coordinator's R1 criteria. As a minimum, the region or interconnection in which a Planning Coordinator's area is located must be identified as an island per R2.3.**				
Robert Martinko	FirstEnergy Energy Delivery	1	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote. Since we do not agree with the standard requirements and have cast a negative vote for the standard, we therefore do not agree with the VSL for the requirements as written.
Kevin Querry	FirstEnergy Solutions	3	Negative	

Voter	Entity	Segment	Vote	Comment
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Douglas Hohlbaugh	Ohio Edison Company	4	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote for the VRF for Requirement R1. Although we agree that Requirement 1 is important because it establishes a sound PSMP, a HIGH VRF assignment is not appropriate and it should be changed to LOWER. By definition, a requirement with a LOWER VRF is administrative in nature, and documentation of a program is administrative. Assigning a LOWER VRF to R1 is more logical since R4, which is the requirement to implement the PSMP, is assigned a MEDIUM VRF because, if violated, it could directly affect the electrical state or the capability of the bulk electric system.
Response: Requirement R1's VRF assignment is a Medium (not a High). The SDT thinks that this requirement is beyond administrative. It is important to the design of UFLS to develop and document criteria to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.				
Kenneth Dresner	FirstEnergy Solutions	5	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote. Since we do not agree with the standard requirements and have cast a negative vote for the standard, we therefore do not agree with the VSL for the requirements as written.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Mark S Travaglianti	FirstEnergy Solutions	6	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote for the standard as written. Although we agree that the Planning Coordinator is the appropriate functional entity to develop and implement a UFLS program, we are concerned with the fact that UFLS entities may not know the specifics of their responsibilities until long after this standard is approved. The SDT should consider adjusting the language of the standard to require more transparency and coordination with the UFLS entities during the PC's development of the UFLS program. Also, per the implementation plan, the PC will be given one year to develop its UFLS program. However, the timeframe for the UFLS entity is based on the schedule imposed by the PC. The implementation plan should allow the UFLS entity at least one year (maybe more per capital budget cycles) from the time the PC identifies the UFLS entity in their UFLS program. The UFLS entity will need sufficient lead time in those instances that require purchase of new UFLS equipment that will require long term budget planning for implementation. The UFLS entities are identified in the UFLS program established by the PC. However, it is not clear where the PC is explicitly required to notify and coordinate with the UFLS entity. In Requirement R3 it is implied that the PC will notify and coordinate with the UFLS entity per the phrase "including a schedule for implementation by UFLS entities within

Voter	Entity	Segment	Vote	Comment
				its footprint". This requirement needs to be more explicit that the PC will notify the UFLS entity, and the measure for R3 needs to require proof that the PC has done this. **Response: The SDT agrees that UFLS Entities should have opportunity to provide input to the Planning Coordinator on what will be required of them.** **The SDT added a requirement to the proposed standard, Requirement R14, to ensure that the Planning Coordinators collect and respond to comments submitted by UFLS entities on the UFLS program, including a schedule for implementation and UFLS design assessment.** We are concerned about the coordination between this UFLS SDT and the GV SDT. It will be difficult to approve and begin implementing the PRC-006-1 standard while the PRC-024-1 standard is still under development and scheduled for approval and implementation at a much later date. For these requirements to be adequately coordinated, the two standards need to be developed, balloted and implemented at the same time. Alternatively, consider adding the following statement in the PRC-006-1 Implementation Plan: "The Effective Date and implementation of this PRC-006-1 standard requires coordination with standard PRC-024-1. Excluding requirement R1, the Effective Date of PRC-006 shall be the later of 1) the completion of the Implementation Plan for PRC-006 or 2) the completion of the Effective Date of the PRC-024-1 standard upon completion of its Implementation Plan." **Response: Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.**
Response: Please see in-line responses.				
James A Ziebarth	Y-W Electric Association, Inc.	4	Negative	From question 3 on the comment form: Regarding the VSLs for R8, the UFLS entities cannot be punished for failing to meet a schedule if the schedule is not mutually agreed upon between the Planning Coordinator and the UFLS entities to ensure that the UFLS entities are capable of meeting such a schedule. At the very least, there must be some protection for the UFLS entities provided that requires the Planning Coordinator(s) to give the UFLS entities long-term notice of the deadlines that they will need to meet. The lack of any scheduling restrictions for the Planning Coordinators in the standard as written has a strong potential to cause enormous burdens on small UFLS entities that simply do not possess the resources to deal with such data reporting requirements without sufficient advance notice. Additionally, the UFLS entities cannot be penalized for failing to submit data in a format over which they have no control or input. The Planning Coordinator should be required to consult with the UFLS entities and decide upon a mutually agreeable data format in order to ensure that the UFLS entities are capable of providing the required data in the required format.

Voter	Entity	Segment	Vote	Comment
				With no language in the standard limiting or clarifying what data can be required of the UFLS entities by the Planning Coordinator, this provision at least should be made to protect small UFLS entities with highly limited resources for dealing with such data reporting requirements.
Response: The SDT added a requirement to the proposed standard, Requirement R14, to ensure that the Planning Coordinators collect and respond to comments submitted by UFLS entities on the UFLS program, including a schedule for implementation and UFLS design assessment.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	It is unclear from the Standard that not forming islands in UFLS design is acceptable. Recommend the SDT consider including language to clarify that is not mandatory that system islands by formed in every UFLS design configuration.
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Scott Heidtbrink	Kansas City Power & Light Co.	5	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Response: The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. To this end, Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. These islands are to be used in UFLS design assessments and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordinate UFLS plans within a region. There are no requirements to identify Planning Coordinator footprints as islands, but all of a Coordinator's area will be included in one island or another.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	No VRF for UFLS should be High. UFLS is only actuated because several other things did not work properly. For a VRF to be High, there must be a direct causal link to bad things happening (i.e. cascading, instability, blackout) as result of the requirement. If UFLS has to be actuated, we have already reached the bad things happening stage and this represents a last ditch effort to save the system because several immediate steps did not prevent the bad things from happening.
Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.				

Voter	Entity	Segment	Vote	Comment
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	NPCC has already implemented a Region specific UFLS Program incorporating a six year UFLS implementation plan, with year one of the plan having ended June, 2010. As such, Con Edison is concerned with how this version of PRC-006 might impact the NPCC Regional UFLS Standard. PRC-006 is not applicable to generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved.
Response: The schedule for implementation by UFLS Entities is at the discretion on the Planning Coordinator and is not set by the standard. The SDT has clarified in the effective date of PRC-006 that the sub-parts related to modeling of generator trip settings will not be effective until PRC-024 is approved and effective. Adding a Generator Owner data requirement to PRC-006 would be redundant and cause double jeopardy concerns. It is the case that some standards are dependent on data requirements found in other standards. An example is that data necessary to comply with TPL standards is required under MOD standards.				
Louise McCarren	Western Electricity Coordinating Council	10	Negative	Opposed to the standard as drafted, so voting against associated VRFs and VSLs Comments submitted will provide specific details
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Lee Schuster	Florida Power Corporation	3	Negative	Progress Energy believes that, overall, the proposed version of NERC Standard PRC-006-01 is acceptable and will provide good direction to the industry. However, we are voting Negative in this ballot, pending resolution of a number of comments that have been submitted via the on-line comment form. The major areas of concern are as follows. 1. Requirements R5 and R13 require two or more Planning Coordinators to "reach concurrence" on UFLS design assessment results. However, no process is provided for resolution if concurrence cannot be reached. 2. Requirement R11 needs to have a threshold such that it is not necessary to perform mandated assessments of smaller islanding events. We suggest a threshold of 500 MW of load, as discussed in the Background discussion section of the Comment Form. 3. Several of the Violation Severity Levels are overly severe regarding assessment studies being late and/or they do not appropriately include a time frame as part of the measure. See the formal comments provided separately by Progress Energy for more details.
Wayne Lewis	Progress Energy Carolinas	5	Negative	
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern, though with a slightly different approach than the commenter's suggestion. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. **The arbitrary qualifier of 500 MW was an item of earlier SDT discussion and inadvertently was left in the comment form. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009. The existing standard PRC-009, which this standard is intended to replace, currently requires that an assessment be performed for all events regardless of size. The SDT cannot remove a requirement from an existing**				

Voter	Entity	Segment	Vote	Comment
standard without a technical justification that explains how this will make the requirement the same or better than what exists today. **Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.**				
Mark Ringhausen	Old Dominion Electric Coop.	4	Negative	R4- REquieres conncurence amongst PCs(maybe in different regions) how do you deteremine whom is non-compliant. **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. The revised standard eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.** What does 'design assessement' mean? **Response: A design assessment is an assessment of the UFLS program design to ensure that the UFLS program meets the performance characteristics (Requirement R3).** R5- What does the SDT meand by 'concurrence' in the requirement? This needs to be clarified. **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern – the term is no longer used. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments.** R12- What do you mean by 'consider' the deficiencis? Must they be resolved? If you mean the PC must resolve them, the say that as 'consider' does not mean this. **Response: An event may reveal that a UFLS program, while compliant with R3, might yet have performed better during the specific event under study. A design assessment is required by R12 to consider any conclusions or recommendations (deficiencies and how to address them) identified in the R11 event assessment relevant to the specific event while maintaining R3 compliance. However, as long as the UFLS program is compliant with R3, the standard cannot require resolution of such deficiencies.**

Voter	Entity	Segment	Vote	Comment
Response: Please see in-line responses.				
Harold Taylor, II	Georgia Transmission Corporation	1	Negative	R5: Need a measure for concurrence. Can two PCs have differing UFLS practices but still attain the needed load shed or must both have the same set point criteria to be in concurrence? **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. The standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area.** R7: While 40 calendar days for the Lower VSL is acceptable, the remaining 10 day intervals should be "working" days. **Response: The SDT thinks that calendar days are appropriate for the 10-day intervals to be consistent with the Lower VSL.** R8: Calendar days should be "working days". Mixing time limit and acceptable PC database format as a penalty can be subjective. **Response: The SDT thinks that calendar days are appropriate; working days are not always the same for everyone. Both time limit and format need to be included somehow in the VSLs. The SDT believes the mix is appropriate.** R11: Lower VSL is an incomplete statement. Delete "to evaluate" from the end. **Response: The SDT made modified the VSL for Requirement R11 by making it a complete statement and replaced “to evaluate” with “evaluated”.**
Response:				
Douglas E. Hils	Duke Energy Carolina	1	Negative	Requirements R5 and R13 contain the problematic requirement to “reach concurrence”, as discussed in our responses to the comment form. The VSLs for these requirements is a solitary Severe VSL which may be impossible to meet, if an entity refuses to reach concurrence.

Voter	Entity	Segment	Vote	Comment
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. The SDT modified both R5 and R13 and made conforming changes to the VSLs. The revised standard eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.				
David Schiada	Southern California Edison Co.	3	Negative	SCE supports WECC's position paper.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots				
Anthony Jankowski	Wisconsin Energy Corp.	4	Negative	see comments on standard
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots				
Tom Bowe	PJM Interconnection, L.L.C.	2	Negative	The ability for the PC to comply with R1 and R2 requires ULFS entities and Transmission Owners to comply with this standard. The VSLs should clearly state that it is the PC who did not meet its obligations under R1 and R2 and not that non-compliance to R1 and R2 was the result of non-compliance by a third party which the PC relied on in meeting its obligations under this standard.
Response: Requirements R1 and R2 of the proposed standard do not involve the Transmission Owners or UFLS entities to perform a task in order for the Planning Coordinators to comply with the requirement. The proposed requirements (R1 and R2) relate to the determination of islanding criteria and the identification of islands in the planning horizon for use in UFLS design assessments. The activities in Requirements R1 and R2 are planning activities that can be accomplished without a Transmission Owner or UFLS entity.				
Laurie Williams	Public Service Company of New Mexico	1	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within a Reliability Region as there are Planning Coordinators. Additionally, the proposed standard does not address UFLS relays which are currently part of the existing program but are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall

Voter	Entity	Segment	Vote	Comment
				into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard requires the identification of Regional Entity footprints as islands to be used in UFLS design assessments (Requirement R2, Part 2.3) and that the Planning Coordinators within each Regional Entity footprint work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within an interconnnection. The SDT believes that a continent-wide standard cannot require single UFLS plans for each interconnection. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design. **Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.**				
Bruce Merrill	Lincoln Electric System	3	Negative	The majority of VSLs and VRFs are acceptable as currently proposed. However, the VSLs for R5 and R13 depend on reaching "concurrence" with other entities, which is not a valid basis for measuring compliance. If the concurrence requirement cannot be revised, then we propose that the VSL levels be reduced. **Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. The SDT still believes that coordination of UFLS plans is important enough that Planning Coordinators must work with each other on both design and event assessments. The revised standard eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas.** Additionally, we would propose reducing the VRFs for R3, R4, R9 and R10 from "High" to "Medium" to account for the fact that primary measures of automatic UFLS programs will normally restore the system even if some UFLS requirements are not completely fulfilled. **Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency,**
Dennis Florom	Lincoln Electric System	5	Negative	
Eric Ruskamp	Lincoln Electric System	6	Negative	

Voter	Entity	Segment	Vote	Comment
				abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.
Response: Please see in-line responses.				
John T. Underhill	Salt River Project	3	Negative	The primary concern identified is that the current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed, the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered, the LSE needs to be included in the Applicability section. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Glen Reeves	Salt River Project	5	Negative	
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard requires the identification of Regional Entity footprints as islands to be used in UFLS design assessments (Requirement R2, Part 2.3) and that the Planning Coordinators within each Regional Entity footprint work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within an interconnection. The SDT believes that a continent-wide standard cannot require single UFLS plans for each interconnection. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE				

Voter	Entity	Segment	Vote	Comment
in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. **The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. The standard does not preclude development of Regional UFLS standards and that approach may address WECC's desire to have one coordinated UFLS design.** **Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.** **The curves are solely for checking the frequency trajectories of simulations and not for setting UFLS relays. The Quebec interconnection has a variance. The other three interconnections are not unique enough to have separate curves, though they could propose variances if they wanted to. They have not. The Planning Coordinators do have the responsibility to determine UFLS design parameters including frequency set points. The SDT decided in the first draft that these parameters should not be determined in a continent-wide standard for the very reason that regions and interconnections have unique characteristics. This is decidedly not a least common denominator approach. The SDT disagrees that the performance characteristic curve approach is reverse engineering, but rather designing to a target. The reliability justification for the curves is their coordination with generator tripping.**				
Dennis Sismaet	Seattle City Light	6	Negative	The standard, requirements, and measurements should reflect the uniqueness of the individual interconnections and not common, continent wide prescriptions.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs.				
John Tolo	Tucson Electric Power Co.	1	Negative	The WECC's Underfrequency Load Shedding Plan is done on an interconnection-wide basis and therefore should have a regional variance as the Quebec Interconnection has. Further, until the WECC has a defined Planning Coordinator this standard, as written, may be applicable to each Balancing Authority's Planning Authority.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots. The terms, "Planning Authority" and "Planning Coordinator" are accepted as identical by both NERC and FERC.				
Larry Akens	Tennessee Valley Authority	1	Negative	TVA believes the following VRF changes should be considered: R4 - change from High to Medium. Justification: The selection of a 5-year interval for assessments seems subjective in nature. Failure to perform an assessment within a 5-year interval would not directly cause or

Voter	Entity	Segment	Vote	Comment
George T. Ballew	Tennessee Valley Authority	5	Negative	contribute to bulk electric system instability. **Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.** R11 - change from Medium to Low. Justification: documenting a post event assessment seems more administrative in nature, relative to R12. **Response: Requirement R12 requires that a post event assessment be conducted as well as documented. If the requirement was only a documentation requirement then the VRF should be a "lower"; however, there is more to the requirement than just documentation.** The Lower VSL for R11 needs work. It appears to simply repeat the requirement rather than stating a violation. **Response: The SDT made conforming changes to the VSL for Requirement R11.** Recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate 12-14 months, High 14-16 months, and Severe greater than 16 months. **Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that grading the timeliness of the study is necessary. The SDT established increments in the VSLs according to the NERC VSL guidelines.** Revise the High and Severe VSL that contain the phrase "shall conduct and document" to read: "conducted and documented." **Response: The SDT made conforming changes to this VSL.** The R4 VSLs should include a consideration of the timeliness of the completion of the study (e.g. lower VSL for 3 months late, Moderate for 3 to 6 months, etc.).

Voter	Entity	Segment	Vote	Comment
				Response: The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that grading the timeliness of the study is necessary.
Response:				
John Canavan	NorthWestern Energy	1	Negative	Voted no to the proposed standard
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Gregory J Le Grave	Wisconsin Public Service Corp.	3	Negative	VRF's for R4 should be reduced from "high" to "medium". System events that would cause UFLS program initiation are rare and are a last resort to preserve the interconnection. The performance of an UFLS program does not change dramatically enough to warrant a "high" VRF for a delay in conducting or documenting a UFLS assessment. **Response: These requirements are assigned a High VRF because the reliability objective of these requirements is to perform an assessment of the UFLS program every five years, provide load shedding, and switching of Elements in accordance with the UFLS program. Violation of these requirements could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.** VSL for R9 is too restrictive. Distribution Providers, particularly small ones, will find it onerous to attempt to manage distribution circuit loads within such tight requirements on its UFLS feeders. **Response: Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. The Planning Coordinator will need to take into account the ability and limitations of small Distribution Providers to allocate load for UFLS. The Distribution Provider can comment on the Planning Coordinator's UFLS program design in this regard via the provision of Requirement R14 peer review.**
Response:				

Voter	Entity	Segment	Vote	Comment
Janelle Marriott	Tri-State G & T Association Inc.	3	Negative	We believe that individual Planning Coordinators are not the appropriate entities to be responsible for determining criteria for areas that may form islands, for identifying the islands, for developing the UFLS program for periodic assessments, for maintaining databases or for assessing events. The current registration by numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. All Planning Coordinators within an interconnection should be required to collaboratively develop an interconnection-coordinated UFLS Plan. Further, Planning Coordinator footprints are neither defined nor is there any guidance on how they should be established. Every VSL that refers to a PC footprint should be clarified. The primary purpose of any UFLS program should is to mitigate the need to form islands by balancing total system loads and resources. It is only a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding events rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts within the interconnection. We strongly believe that there should be recognized sub-area group(s), which consist of PCs, as assigned by the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate or address the interconnection reliability needs There is also a concern that EOP-003-2 is currently being balloted based on changes made as a part of the Order 693 Directives. The two versions are not compatible. We believe that “ownership” should be removed from the criteria because it may be different from the operating or controlling entity and both entities cannot be responsible. Load Serving Entities should also be included as a “possible” UFLS entity. Some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. Each interconnection should establish discrete set points based upon stability and dynamic analysis. From discrete set points one can establish criteria which are measurable and performance based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC. Furthermore, the Standard needs to be very explicit that the curves are interconnection performance curves and not specific protective relay set points. The standard should adequately recognize the performance characteristics of different type of generation and a variance should not be required. Faster acting and greater inertia systems should be allowed the operating margins appropriate to their systems. Real

Voter	Entity	Segment	Vote	Comment
				differences exist between interconnections. The standard and its performance requirements should reflect this fact. This would allow for the uniqueness of each interconnection to be addressed similar to Hydro Quebec's variance.
Response: The SDT believes the Planning Coordinator, having a wide-area view and the necessary technical skills, is the proper entity to oversee the design and implementation of UFLS. There is also wide industry support for the Planning Coordinator as the proper entity for UFLS. The SDT recognizes the need to at least preserve coordination on the regional level and has inserted a requirement (Requirement R2, Part 2.3) to identify each Regional Entity footprint as an island to be assessed for UFLS performance. The PC's within each region will need to work with each other in order to produce a successful assessment. **The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.** **The scope of work addressed under the Order 693 Directives was revised so that Project 2010-12 no longer addresses EOP-003.**				
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	We cannot vote affirmative on the VRFs and VSLs until concerns on the proposed standard have been addressed.
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				
Charles H Yeung	Southwest Power Pool	2	Negative	We disagree with the enforcement of requirements if a subject registered entity will have to rely on another yet to be approved standards to be fully compliant. A generator/owner operator must be held responsible to provide UFLS data to the PC. The SDT has denied a request to add GOs into the PRC-006 citing such a requirement falls outside the scope of this standard and will be addressed in a separate standard. Nonetheless, adoption of this version of PRC-006 will subject PCs to account for all bulk power system devices that affect UFLS schemes, but lacks the ability to force a GO to provide needed data. NERC compliance must realize such gaps exist and enforce these requirements with that knowledge. These VSLs do not recognize such a gap.
Response: The responsibility of generator owners resides within a standard under development currently, PRC-024. Per the implementation schedule proposed for PRC-006, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.				
Richard J. Padilla	Pacific Gas and Electric Company	5	Negative	We have voted no due to our negative vote on the standard recommend that the VRF and VSL be addressed after the standard comments are resolved
Response: Please see the SDT responses to the comments in the Consideration of Comments report for the formal comment period conducted in June-July, 2010. In addition, please see the response to comments to the subsequent ballots.				

Voter	Entity	Segment	Vote	Comment
Paul B. Johnson	American Electric Power	1	Affirmative	As AEP has stated in other projects, setting a VSL at "Severe" for a binary outcome could be challenged as being arbitrary and another level should be used as the starting point.
Edward P. Cox	AEP Marketing	6	Affirmative	
Response: In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use specific guidelines for determining whether to approve VSLs: Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties A violation of a "binary" type requirement must be a "Severe" VSL. The SDT must comply with the FERC VSL guidelines.				

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Project 2007-01 Underfrequency Load Shedding
Date of Initial Ballot: July 7-17, 2010

Summary Consideration:
During the third posting of PRC-006-1 and EOP-003-2 the standard drafting team made several conforming changes as a result of the industry comments received.

The fourth version of the proposed standard addresses the coordination issue many commenters expressed. Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.

Commenters expressed confusion over having Transmission Owners as part of UFLS Entities but separated out as Transmission Owners in Requirement R10 and suggested combining R9 and R10. The team reviewed the rationale for this structure. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements.

Commenters expressed that the wording in Requirement R10 “switching of elements” is confusing. The team modified Requirement R10 to clarify that it means: “switching of capacitor banks, Transmission Lines, and reactors” in order to control over voltage as a result of under frequency load shedding.

Many commenters indicated that Generator Owners should be included in the applicability of the standard. Some suggested including a data requirement in PRC-006-1 that requires the Generator Owners to submit the necessary data to accomplish Requirement R4; however, the team felt that because such a data requirement already exists in PRC-024 and because the team has clarified in the effective date of the standard that the sub-parts related to generators will not be effective until PRC-024 is approved and effective that adding such a data requirement to PRC-006 would be redundant and possibly cause double jeopardy concerns.

The standard drafting team received several comments on EOP-003 that expressed concern that the removal of under-frequency load shedding in the standard was not clear enough. The standard drafting team made modifications to the EOP-003 requirements that clarify that the load shedding referred to in the requirements exclude automatic under-frequency load shedding.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	(1) PRC-006, R1 should be modified such that PC is required to coordinate development of the islanding criteria in consultation with TO and TP. Further, presently the RE is involved in performing or coordinating the islanding/UFLS studies. We believe that RE should continue to be involved. (2) PRC-006, R2.3 No basis provided for criteria included in the second part of R2.3; that is, each RE footprint that resides in the PC footprint is to be identified as an island. (3) EOP-003-1, R2, the last phrase should be modified from "...load shedding scheme is required." to "...load shedding scheme is necessary to minimize the risk of uncontrolled failure of the interconnected system to match the "Purpose" of the standard.
Response: Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model version 5.				
George T. Ballew	Tennessee Valley Authority	5	Negative	"Comments associated with the negative vote are contained in the Project 2007-01 comment form submitted by TVA."
Response: Please see our response to your comments.				
Henry Delk, Jr.	SCE&G	1	Negative	1) SCE&G proposes an effective date of 24 months after regulatory approval. We believe the currently proposed effective date of 12 months after regulatory approval would not allow enough time to ensure compliance due to the requirements to establish criteria to identify islands, coordinate results with other Planning Coordinators, and reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion. A number of these requirements cannot be met until a prior requirement is completed and each of these requirements requires coordination with other utilities which will increase the amount of time necessary to obtain compliance. As a result, SCE&G believes an effective date of 24 months after regulatory approval would be much more practical and desirable than the currently proposed 12 month effective date. **Response:** The standard drafting team received feedback that many of the existing UFLS programs meet the performance characteristics in the proposed standard. Once this standard is approved the entities with existing programs would need a year to validate their program and validate the schedule for implementation with the UFLS entities. 2) The graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a
Matt H Bullard	South Carolina Electric & Gas Co.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curves data points. **Response:** The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	1. R5 and R13 require that both or all the PC's reach concurrence on the assessment of the UFLS performance in an island. One entity might have larger margin requirements or a different methodology compared to another entity. These differences might not be reconcilable. A standard should not require that one PC has to agree with another PC. **Response:** The standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model version 5. 2. R11 needs to have a MW size threshold for requiring the assessment of an UFLS event. As written, this requirement could require an assessment of an event where a breaker opened on a radial 115 kV line which had an 8 MW generator and 15 MW of load on the feeder. Such a small event has no consequence to the reliability of the BES. A MW threshold of 500 MW would be appropriate. 3. Miscellaneous improvements required to wording of R5, M5, and several VSL's. **Response:** PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	
Gwen S Frazier	Gulf Power Company	3	Negative	
Don Horsley	Mississippi Power	3	Negative	
Response:				
Bruce Merrill	Lincoln Electric System	3	Negative	Although Draft 3 contains many significant improvements over previous drafts, LES believes the standard can be further refined to incorporate important issues that are not adequately addressed at this time. Please see the MRO NSRS group comments for LES'

Voter	Entity	Segment	Vote	Comment
Dennis Florom	Lincoln Electric System	5	Negative	specific concerns. **Response:** The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.
Eric Ruskamp	Lincoln Electric System	6	Negative	
Linda R. Jacobson	City of Farmington	3	Negative	Another concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.				
Gregory Campoli	New York Independent System Operator	2	Negative	Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved. This standard seems to be contrary to FERC's stated concern (Oct. 2009 Washington DC meeting) to develop a standard that can support the program it was designed to enforce.....the applicability as stated in the standard and by NERC registry criteria restricts and excludes the need for GO's that may in aggregate be necessary for a reliable UFLS program, to adhere to the standard. The standard also is potentially in conflict with the work being done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. Sufficient coordination on NERC Standards development needs to occur on a going forward basis.
Response: The suggestion to include the Generator Owners in the proposed standard is problematic because such a data requirement already exists in PRC-024 and because the team has clarified in the effective date of the standard that the sub-parts related to generators will not be effective until PRC-024				

Voter	Entity	Segment	Vote	Comment
is approved and effective that adding such a data requirement to PRC-006 would be redundant and possibly cause double jeopardy concerns.				
Jason Shaver	American Transmission Company, LLC	1	Negative	ATC is voting negative for the following reasons. These comments were submitted in our NERC comment form. M5 - As noted in the comments below for R5, replace the words "reached concurrence with" with "provided a UFLS design assessment report to". Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words "other affected Planning Coordinators" with "other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of "other affected Planning Coordinators" is too vague and could be interpreted and categorized differently by various entities and auditors. M7 - As noted in the comments below for R7, replace "within their Interconnection", with "that have design assessment responsibilities within the islands covered by the UFLS database". Planning Coordinators that are within the same Interconnection, but are not within any islands covered by another Planning Coordinators UFLS database, would not need to receive the UFLS information. M10 - Replace "automatic switching of Facilities" with "automatic switching of Elements" to be consistent with the associated Requirement R10. We propose that the scope of the SAR be revised to call for removing the automatic UFLS requirements from EOP-003-1 and referring them to PRC-006-1 standard, and for also removing the automatic UVLS requirements from EOP-003-1 and referring them to a new PRC standard. In line with the comments for Question 6: R2 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and new PRC standard. R3 - add the qualification "coordinate manual load shedding plans". R4 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard. R5 - add the qualification "implement manual load shedding plans". R7 - remove this requirement because it refers to automatic load shedding plans, let this be covered by PRC-006-1 and a new PRC standard. 1. In R3, the term, "imbalance", should be described using the standard industry nomenclature of imbalance = (load-generation)/generation. 2. In R4, we interpret that the Equivalent Inertia Analysis is a valid dynamic simulation methodology for certain aspects of UFLS assessments. So, we expect that this type of dynamic analysis would be accepted toward compliance with the "through dynamic simulation" portion of this requirement Attachement 1 for R4.1, R4.2, R4.3 3. The title for Attachment 1 should clearly qualify that this curve applies for a 25% or less island imbalance. The curves that should be used for UFLS programs associated with imbalance levels greater than 25% (e.g. 30%, 40%, 50%) would be different from the 25% curve. 4. The Under Frequency Performance Characteristic line in Attachment 1 should be extended to 59.5 Hz (at 500 sec). The reason for this change is that the worst case response between 58.7 Hz and 59.5 Hz may occur for imbalance conditions significantly less than 25% where the governor response prevents the load shedding blocks from

Voter	Entity	Segment	Vote	Comment
				picking up and where response recovery times is a function of governor response and system inertia (30 seconds to 500 seconds). This removes the knee of the curve at 30 seconds and extends the curve up to 500 seconds. This would change the 30 second at 58.9 Hz cut off point to 500 seconds. 5. Add a note to Attachment 1 that states, "Larger size UFLS programs (e.g., 40%) may require less restrictive (lower and/or longer time delays) underfrequeny limits due to island generation and protection characteristics." UFLS programs shedding more than 25% must increase generation protection delay times and/or change set points to achieve coordination with load shedding. For example, Manitoba Hydro and Saskatchewan need to shed more than 30% of the area load to achieve reasonable frequency recovery in their islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable. Attachment 2 for R4.4, R4.5, R4.6 6. The title for Attachment 2 should clearly qualify that this curve applies for a 25% or less island imbalance. The curves that should be used for UFLS programs associated with imbalance levels greater than 25% (e.g. 30%, 40%, 50%) would be different from the 25% curve. Generator Underfrequency and Overfrequency Attachments 7. The Generation Owner off-nominal frequency coordination requirements and coordination curves should be included in the PRC-006 standard. The generation curves should be applicable for load shedding levels beyond the 25% (e.g. 30%, 40%, 50%). If curves beyond 25% are not include, then the titles of the curves should qualify that they apply for 25% imbalance and include an note regarding coordination with UFLS programs that shed higher than 25% of the island load. The line should extend to 57 Hz (at .3 sec) to 59.5Hz (at 1800 sec). The minimum frequency of 57.0 Hz was chosen because most conventional generation can briefly operate down to 57.0 Hz and large load shedding programs may need to make use of that capability to achieve coordination with these UFLS programs. Volts/Hertz Performance Characteristic 8. The Volts/Hz requirement should be removed. This performance characteristic cannot presently be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation. In addition, the Volts/hertz requirement is not need in this standard. Voltage regulators automatically reduce voltage according to volts per hertz when in the automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist that adequately address the volts/Hz issue. Replace the words “reach concurrence with” with “provide UFLS design assessment results to”. Fulfillment of a compliance measure that involves reaching concurrence with another entity is dependent on the other entity and can be outside of the control of the Planning Coordinator. In addition, replace the words “other affected Planning Coordinators” with “other Planning Coordinators that have design assessment responsibilities for islands covered in the design assessment report. The qualification of “other affected Planning Coordinators” is too vague and could be interpreted and categorized differently by various

Voter	Entity	Segment	Vote	Comment
				entities and auditors. Consideration should be given to replacing “Transmission Owner” with “UFLS Entity” because the automatic switching of distribution Elements (e.g. capacitor banks) may be more effective and practical UFLS design than restricting the scope of the requirement to just transmission Elements. 1. For R11, replace “Each Planning Coordinator, in whose footprint . . . to evaluate” with “When a disturbance event occurs in a Planning Coordinator’s footprint that involves automatic UFLS program operation or frequency excursions should have activated UFLS program operation, and a final disturbance report is required per EOP-004, each Planning Coordinator shall evaluate within one year of the disturbance event:”. 2. Either part of or after R11, there should be a requirement that “Each Planning Coordinator shall provide a preliminary event assessment report to the other Planning Coordinators who must conduct an assessment of the event for review at least 90 days before finalizing the event assessment report. 3. For R13, replace “in whose footprint . . .on the event assessment result” with “that conducts an UFLS design assessment (per R12) for islands where other Planning Coordinators have design assessm
Response: Please see our responses to your comments in the consideration of comments report.				
Scott Kinney	Avista Corp.	1	Negative	Avista has the following comments o The proposed standard fails to address UFLS relays which are currently part of the program which are owned by the customer. This is critical to have a successful program. In addition the UFLS- DT believes to assure areas are covered the LSE needs to be included in the Applicability section. **Response:** The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; “For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. o EOP-003-1 or the proposed EOP-003-2 and the proposed PRC-006 both address automatic UFLS -- only one standard should address the automatic UFLS -- two standards lead to confusion and potential double jeopardy. **Response:** The standard drafting team made modifications to the EOP-003 requirements that clarify that the load shedding referred to in the requirements excludes automatic under-frequency load shedding. o The proposed measures are vague, not specific and not performance based which leave too much up to the Auditor’s interpretation. **Response:** The SDT thinks that the Measures identify the evidence or types of evidence needed to demonstrate compliance with the associated requirement. The SDT thinks that the commenter is proposing that the SDT propose the RSAW not the Measures.

Voter	Entity	Segment	Vote	Comment
				o The proposed requirements are not well defined and are hard to apply in some cases, which leads to a problem with the proposed "Violation Severity Levels". Unclear and not well defined requirements cause a disconnect with the Violation Severity Levels. o The proposed standard does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. **Response:** The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard. o The primary purpose of the UFLS Plan is designed to mitigate the need to form islands by balancing loads and resources. It is a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding event rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs effort within the interconnection. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. o The WECC UFLS-DT believes there should be recognized sub-area groups, (consisting of PCs, as assigned by the Reliability Assurer (RA)). These sub-groups would be the agent for the PCs, and would assure the overall coordination within the interconnection. For example, the WECC RA recognizes the following sub-areas for UFLS coordination within the Western Interconnection (WI): Southern Islanding Load Tripping Group, the Northwest Power Pool UFLS group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-groups, PCs could randomly form sub-area groups whose plans may not coordinate on an interconnection wide basis or even address the interconnection reliability needs, but coordinated among the randomly formed sub-groups. **Response:** Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and

Voter	Entity	Segment	Vote	Comment
				conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. o The proposed standards attempt to establish a continent wide with frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.
Claudiu Cadar	GDS Associates, Inc.	1	Negative	Besides the commented answers to the NERC questions within the comment form, GDS Associates has the following additional comments as follows: - Effective Date. Depending on when this standard is mandatory and enforceable, it may fall between entities' budgeting periods. An 18 months implementation would allow for all entities to budget the funds necessary to implement the standard. **Response:** The standard drafting team received feedback that many of the existing UFLS programs meet the performance characteristics in the proposed standard. Once this standard is approved the entities with existing programs would need a year to validate their program and validate the schedule for implementation with the UFLS entities. - Requirement R8. How the UFLS entity suppose to provide data to the Planning Coordinator and when is suppose to do that? The Planning Coordinator can make its UFLS database available within 30 days upon request (see Requirement R7.) **Response:** The standard drafting team added a requirement to the proposed standard to collect and respond to comments on the UFLS program, schedule for implementation and for the collection of data for the UFLS database (Requirement R14). - Requirement R9, R10. What if the UFLS entity does not agree with Planning Coordinator's assessment? - Requirement R10 should be further elaborated - Measure M10. There is no BES term for "automatic switching". The measure should be reworded

Voter	Entity	Segment	Vote	Comment
				for a clear understanding. **Response:** The standard drafting team added a requirement to the proposed standard to collect and respond to comments on the UFLS program, schedule for implementation and for the collection of data for the UFLS database (Requirement R14). The team modified Requirement R10 to clarify that it means: "switching of capacitor banks, Transmission Lines, and reactors" in order to control over voltage as a result of under frequency load shedding.
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	Comment: NPCC has already implemented a Region specific UFLS Program incorporating a six year UFLS implementation plan, with year one of the plan having ended June, 2010. As such, Con Edison is concerned with how this version of PRC-006 might impact the NPCC Regional UFLS Standard. Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved.
Response: The standard drafting team provided clarifying examples in the implementation schedule to clarify that entities with existing programs and schedules for implementation will need to validate their existing programs against the standard's requirements and collect feedback from the UFLS entities as required by the standard.				
Larry Akens	Tennessee Valley Authority	1	Negative	Comments associated with the negative vote are contained in the Project 2007-01 comment form submitted by TVA
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	
Response: Please see our response to your comments in the consideration of comments report.				
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	comments provided on comment form
Response: Please see our response to your comments in the consideration of comments report.				
Robert W. Roddy	Dairyland Power Coop.	1	Negative	concerned that generation limits are too conservative.
Response: Please see our response to your comments in the consideration of comments report.				
Russell A Noble	Cowlitz County PUD	3	Negative	Cowlitz believes the comments of BPA and WECC concerning the current draft of the Standard need to be addressed before a positive vote can be cast.

Voter	Entity	Segment	Vote	Comment
Rick Syring	Cowlitz County PUD	4	Negative	**Response:** Please see our response to your comments in the consideration of comments report. One troubling aspect is the current ownership of UFLS relays by end-use customers, put in place during the voluntary compliance reliability era. These relays, buried deep into the customer's plant is necessary to allow safe load shedding. Placing the relays in the Distribution Provider's facilities is not possible without compromising the safety of plant personnel or the loss of significant plant product and equipment due to an uncontrolled plant shut down. In such situations, it is not palatable to require end-use customers to register; it is also not fair to force the Distribution Provider to negotiate with the customer, assuming the DP and LSE are not the same entity. Therefore, it is the LSE who must deal with the customer and the subsequent negotiation of contract agreements for the maintenance of customer owned equipment necessary for UFLS. It must be strongly noted that the LSE should not be required to own, or maintain the equipment. The LSE can only act as the reliability emissary in negotiating with the customer in this regard, however it is difficult to pass on any consequence of reliability violations to the customer. Should the customer be remiss in the upkeep of the relays, the LSE is then subject to compliance penalties over actions it has little control of. Also keep in mind of the complexity of PRC-005-2 applicability to the customer's electrical facilities due to the UFLS relay present there. This is truly a compliance nightmare of great concern to Cowlitz. **Response:** The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.
Bob Essex	Cowlitz County PUD	5	Negative	
Paul Morland	Colorado Springs Utilities	1	Negative	CSU offers the following comments: R3 (Attachments) It is not clear how attachment 1 should be used. Are the curves performance curves? Set point curves? R10 Need more clarity on what is meant by "Automatic Switching of Elements"? Does it mean a TO needs to automatically switch capacitor banks to avoid overvoltages?
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.				
John K	Dominion Virginia	1	Negative	Currently there is no requirement for Generator Owners to provide trip settings for non-

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Loftis	Power			conforming units to the Planning Coordinator. Absent such a requirement, the responsibility for compliance would be placed on the Transmission Owner. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. So, we suggest the addition of a requirement (applicable to the Generator Owner) to provide the information (as needed in R3-R3.3.3) to the Planning Coordinator.
Michael F Gildea	Dominion Resources Services	3	Negative	
Mike Garton	Dominion Resources, Inc.	5	Negative	
Louis S Slade	Dominion Resources, Inc.	6	Negative	
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.				
Stanley M Jaskot	Entergy Corporation	5	Negative	Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. I n M3 it is unclear what action is intended by the phrase “including the criteria itself”. Since the criteria is specified in R3, it is recommended that the phrase be deleted. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: “Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators.” We also recommend that the wording in R5 be changed to: “Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint.”

Voter	Entity	Segment	Vote	Comment
				The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. We also recommend that the High and Severe VSLs that contain the phrase "shall conduct and document" to read "conducted and documented". The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information. The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the 500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events.
Response: Please see our response to your comments in the consideration of comments report.				

Voter	Entity	Segment	Vote	Comment
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	Entities should be required to inform neighbors of the assessment results rather than reaching concurrence. With the approach currently in the standard, an entity could potentially be held responsible for inaction of another planning coordinator. The language should say, "Each Transmission Operator and Balancing Authority shall coordinater load shedding plans among other interconnected entities." Also MidAmerican notes that under frequency event analyses are complex. Therefore, the minimum time frames for anlysis and implementation should be increased to at least 2 years and exception requests for additional time should be allowed.
Response: In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	EOP-003-1 - BC Hydro does not agree with the EOP-003-1 changes. BC Hydro believes that the standard should not be specific to UVLS plans but rather on load shedding plans which may include AUVLS, AUFLS and manual load shedding. If EOP-003 is only for UVLS we don't know how we would be expected to "coordinate" this with other BA's. **Response:** The standard drafting team received several comments on EOP-003 that expressed concern that the removal of under-frequency load shedding in the standard was not clear enough. The standard drafting team made additional modifications to the EOP-003 requirements that clarify that the load shedding referred to in the requirements excludes automatic under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1. PRC-006-1 The frequency performance requirements may vary depending on individual system characteristics. NERC standard on AULS should stay at a high level. The detailed requirements should be left to subgroups to deal with based on their uniqueness and coordinate within their interconnections. - The standards should mainly deal with under-frequency load shedding. The frequency performance on generators should be left to generation interconnection or planning standards. **Response:** The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those

Voter	Entity	Segment	Vote	Comment
				generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.
Daniel Brotzman	Commonwealth Edison Co.	1	Negative	EOP-003-1 needs to define the criteria as to when and how UVLS schemes are installed to provide consistency direction to Planning Coordinators and the entities that have to install UVLS schemes. The relationship between the use of UVLS and compliance with TPL-001 standards should be clarified. Is load shedding (including UVLS) allowed to meet the performance criteria in TPL-001? The standard should define when UVLS are applicable to the BES and thus subject to the requirements of EOP-003. UVLS schemes developed for distribution or other purposes beyond criteria should not be discouraged through regulatory burden. UVLS should be carefully defined. Many types of load will cut out on low voltage. **Response:** The standard drafting team received several comments on EOP-003 that expressed concern that the removal of under-frequency load shedding in the standard was not clear enough. The standard drafting team made additional modifications to the EOP-003 requirements that clarify that the load shedding referred to in the requirements exclude automatic under-frequency load shedding. There is another NERC project tasked with making comprehensive revisions to EOP-003. The intent of the supplemental SAR was to focus solely on removing conflicts and redundancies related to underfrequency load shedding in EOP-003-1. PRC-006-01: The standard lacks guidance as to what the trip settings should be. It is not clear as to how Attachment 1 should be used and doesn't provide specific detail for under frequency set points. Exelon disagrees that R3.3 is easier to understand. Clarification is needed as to where the underfrequency set points are. Do all entities contribute equally to Attachment 1? There needs to be a standardized relationship between GO and TO/DP participation in obtaining the desired level of system performance. There should also be explicit criteria as to what the expectations are for each individual entity. It should be clear that all UFLS entities are to participate equally and that larger entities will not be expected to carry the burden for smaller entities. There should be some recognition in the standard that UFLS schemes currently exist and effort should be made to avoid needlessly changing relays or settings on many thousands of installations if some arbitrary and common set points were to be determined by the PC, thus causing needless expense. It is likely desirable to have slightly different settings for UFLS across a footprint so as to not create load changes that are too abrupt. The current practice of allowing contractual agreements between GOs and DPs for additional load shedding as a voluntary business decision, in the event that a unit owner doesn't comply with the unit trip settings should be addressed. Exelon does not agree with

Voter	Entity	Segment	Vote	Comment
				the concept of allowing neighboring Planning Coordinators to define or modify islanding criteria. **Response:** The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters. There should be a single criteria for the determination of an island which is consistent across the interconnection, unless a specific geographic or regional exception is identified. Even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint. **Response:** The proposed standard requires the Planning Coordinators to establish the criteria for selecting islands and does not allow another Planning Coordinator to modify the criteria established in Requirement R1.
Robert Martinko	FirstEnergy Energy Delivery	1	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote for the standard as written. Although we agree that the Planning Coordinator is the appropriate functional entity to develop and implement a UFLS program, we are concerned with the fact that UFLS entities may not know the specifics of their responsibilities until long after this standard is approved. The SDT should consider adjusting the language of the standard to require more transparency and coordination with the UFLS entities during the PC's development of the UFLS program. Also, per the implementation plan, the PC will be given one year to develop its UFLS program. However, the timeframe for the UFLS entity is based on the schedule imposed by the PC. The implementation plan should allow the UFLS entity at least one year (maybe more per capital budget cycles) from the time the PC identifies the UFLS entity in
Kevin Querry	FirstEnergy Solutions	3	Negative	

Voter	Entity	Segment	Vote	Comment
Douglas Hohlbaugh	Ohio Edison Company	4	Negative	their UFLS program. The UFLS entity will need sufficient lead time in those instances that require purchase of new UFLS equipment that will require long term budget planning for implementation. The UFLS entities are identified in the UFLS program established by the PC. However, it is not clear where the PC is explicitly required to notify and coordinate with the UFLS entity. In Requirement R3 it is implied that the PC will notify and coordinate with the UFLS entity per the phrase “including a schedule for implementation by UFLS entities within its footprint”. This requirement needs to be more explicit that the PC will notify the UFLS entity, and the measure for R3 needs to require proof that the PC has done this. We are concerned about the coordination between this UFLS SDT and the GV SDT. It will be difficult to approve and begin implementing the PRC-006-1 standard while the PRC-024-1 standard is still under development and scheduled for approval and implementation at a much later date. For these requirements to be adequately coordinated, the two standards need to be developed, balloted and implemented at the same time. Alternatively, consider adding the following statement in the PRC-006-1 Implementation Plan: "The Effective Date and implementation of this PRC-006-1 standard requires coordination with standard PRC-024-1. Excluding requirement R1, the Effective Date of PRC-006 shall be the later of 1) the completion of the Implementation Plan for PRC-006 or 2) the completion of the Effective Date of the PRC-024-1 standard upon completion of its Implementation Plan."
Kenneth Dresner	FirstEnergy Solutions	5	Negative	**Response:** The SDT added a requirement to the proposed standard, Requirement R14, to ensure that the Planning Coordinators collect and respond to comments submitted by UFLS entities on the UFLS program, including a schedule for implementation and UFLS design assessment.
Mark S Travaglianti	FirstEnergy Solutions	6	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote. Since we do not agree with the standard requirements and have cast a negative vote for the standard, we therefore do not agree with the VSL for the requirements as written.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.				

Voter	Entity	Segment	Vote	Comment
James A Ziebarth	Y-W Electric Association, Inc.	4	Negative	From Question 3 on the comment form: Regarding the VSLs for R8, the UFLS entities cannot be punished for failing to meet a schedule if the schedule is not mutually agreed upon between the Planning Coordinator and the UFLS entities to ensure that the UFLS entities are capable of meeting such a schedule. At the very least, there must be some protection for the UFLS entities provided that requires the Planning Coordinator(s) to give the UFLS entities long-term notice of the deadlines that they will need to meet. The lack of any scheduling restrictions for the Planning Coordinators in the standard as written has a strong potential to cause enormous burdens on small UFLS entities that simply do not possess the resources to deal with such data reporting requirements without sufficient advance notice. Additionally, the UFLS entities cannot be penalized for failing to submit data in a format over which they have no control or input. The Planning Coordinator should be required to consult with the UFLS entities and decide upon a mutually agreeable data format in order to ensure that the UFLS entities are capable of providing the required data in the required format. With no language in the standard limiting or clarifying what data can be required of the UFLS entities by the Planning Coordinator, this provision at least should be made to protect small UFLS entities with highly limited resources for dealing with such data reporting requirements. From Question 8 on the comment form: Because Load Serving Entities (not Distribution Providers) are actually responsible for the load in the current Functional Model and Compliance Registry Criteria, they should also be included in the applicability section of this standard. From Question 12 on the comment form: Y-WEA is concerned about this requirement in that it seems to require the installation of facilities rather than just relays. 16 USC 824o (a)(3) gives NERC the authority to regulate existing facilities and planned additions or modifications to those facilities, not to prompt or require modifications or additions to the existing facilities. This proposed requirement seems to run afoul of this section of the USC.
Response: The SDT added a requirement to the proposed standard, Requirement R14, to ensure that the Planning Coordinators collect and respond to comments submitted by UFLS entities on the UFLS program, including a schedule for implementation and UFLS design assessment.				
Kim Warren	Independent Electricity System Operator	2	Negative	Generator owners are not included in the Applicability Section of this standard. We understand from the SDT's responses to the last posting that there is a separate project for generator requirements that would obligate them to provide the required information to the Planning Coordinators with which to design the underfrequency load shedding program. Absent that standard, a Generator Owner has no obligation to provide the necessary data to the Planning Coordinators which can result in the Planning Coordinator failing to meet the PRC-006-1 standard. We therefore request that Generator Owner be included in the Applicability Section and a requirement for it to provide the needed information to the Planning Coordinator be added, or balloting of standard PRC-006-1 be deferred until such a requirement in that other standard is ready for balloting.

Voter	Entity	Segment	Vote	Comment
Response: Many commenters indicated that Generator Owners should be included in the applicability of the standard. Some suggested including a data requirement in PRC-006-1 that requires the Generator Owners to submit the necessary data to accomplish Requirement R4; however, the team felt that because such a data requirement already exists in PRC-024 and because the team has clarified in the effective date of the standard that the sub-parts related to generators will not be effective until PRC-024 is approved and effective that adding such a data requirement to PRC-006 would be redundant and possibly cause double jeopardy concerns.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	Instead of reaching concurrence, entities should be just required to inform neighbors of the assessment results. Otherwise entities could potentially be held responsible for inaction of another planning coordinator. The language could be changed to be consistent with the language in EOP-003 R3, such as, "Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected (entities)". MidAmerican notes that past under frequency event analyses are complex and that the minimum time frames for analysis and implementation should be increased to at least 2 years and exception requests for additional time should be allowed.
Response: In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	It is unclear from the Standard that not forming islands in UFLS design is acceptable. Recommend the SDT consider including language to clarify that is not mandatory that system islands by formed in every UFLS design configuration.
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Scott Heidtbrink	Kansas City Power & Light Co.	5	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Response: The proposed standard requires that an island be the basis of UFLS program design – at a minimum Requirement R2 part 2.3 A single island that includes all portions of the BES in either the Regional Entity footprint or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island.				

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Michael Moltane	International Transmission Company Holdings Corp	1	Negative	ITC Holdings strongly suggests that the "planning coordinator" as it relates to UFLS be clearly defined. As written throughout the standard, ITC would be responsible for planning UFLS when we don't own any such systems. Due to the huge impact the definition of "planning coordinator" has on this standard, and the ambiguity that exists with the definition of this entity, ITC must vote negative
Response: An entity that is registered as the Planning Coordinator (or the previous name for the function – Planning Authority), must be prepared to accept responsibility for the requirements assigned to that function. The terms Planning Authority and Planning Coordinator have the same meaning, and are defined in the NERC Glossary of Terms Used in Reliability Standards. The Planning Coordinator does not necessarily own UFLS systems but rather coordinates the planning of such systems among the entities that own, operate and control UFLS.				
Terri F Benoit	Entergy Services, Inc.	6	Negative	NEGATIVE BALLOT WITH REASONS Entergy Ballot PROJECT 2007-01 UNDERFREQUENCY LOAD SHEDDING PROGRAM REQUIREMENTS Ballot Ending July 16, 2010 The following are the reasons associated with our Negative Ballot. Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. In M3 it is unclear what action is intended by the phrase “including the criteria itself”. Since the criteria is specified in R3, it is recommended that the phrase be deleted. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: “Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators.” We also recommend that the wording in R5 be changed to: “Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint.” The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. We also recommend that the High and Severe VSLs that contain the phrase “shall conduct and document” to read “conducted and documented”. The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC

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				change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information. The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the 500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events.
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.				
Richard Salgo	Sierra Pacific Power Co.	1	Negative	Negative vote prompted by several concerns: First, the Standards as proposed are a disturbing departure from the present practice of Regional and Interconnection-wide coordination of off-nominal frequency protection. We feel that it must be approached on an Interconnection-wide basis, not as individual Planning Coordinators. The goal should be that the Planning Coordinators develop a coordinated interconnection-wide off-nominal frequency scheme design. This is imperative to ensure adequate UFLS protection across the Interconnection. Secondly, applicability does not appear to include entities who must be responsible to ensure that the UFLS is carried out, for instance, the LSE's and DP's that necessarily must implement the prescribed UFLS protection devices at the distribution level. Finally, we disagree with the concept of frequency-vs-time curves, as this approach will fall short of addressing the unique characteristics of the various NERC Interconnections.
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay				

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within those curves by some margin, e.g., between the two curves of Attachment 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters. Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.				
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	NPCC has already implemented a Region specific UFLS Program incorporating a six year UFLS implementation plan, with year one of the plan having ended June, 2010. As such, Con Edison is concerned with how this version of PRC-006 might impact the NPCC Regional UFLS Standard. Applicability of PRC-006, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved.
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	
Response: The standard drafting team received feedback that many of the existing UFLS programs meet the performance characteristics in the proposed standard. Once this standard is approved the entities with existing programs would need a year to validate their program and validate the schedule for implementation with the UFLS entities. A data requirement already exists in the proposed PRC-024 - the team has clarified in the effective date of the standard that the Parts of the requirement related to generators will not be effective until PRC-024 is approved and effective, that adding such a data requirement to PRC-006 would be redundant and possibly cause double jeopardy concerns.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	oThe proposed measures are vague, not specific and not performance based which leave too much up to the Auditor's interpretation. **Response:** The SDT thinks that the Measures identify the evidence or types of evidence needed to demonstrate compliance with the associated requirement. The SDT thinks that the commenter is proposing that the SDT propose the RSAW not the Measures. oThe proposed standard does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a

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				secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. oThe primary purpose of the UFLS Plan is designed to mitigate the need to form islands by balancing loads and resources. It is a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding event rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not and individual island issue and therefore not driven by an individual PC but by a coordination of PCs effort within the interconnection. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. o The WECC UFLS-DT believes there should be recognized sub-area groups, (consisting of PCs, as assigned by the Reliability Assurer (RA)). These sub-groups would be the agent for the PCs, and would assure the overall coordination within the interconnection. For example, the WECC RA recognizes the following sub-areas for UFLS coordination within the Western Interconnection (WI): Southern Islanding Load Tripping Group, the Northwest Power Pool UFLS group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-groups, PCs could randomly form sub-area groups whose plans may not coordinate on an interconnection wide basis or even address the interconnection reliability needs, but coordinated among the randomly formed sub-groups. The standard, requirements, and measurements should reflect the uniqueness of the individual interconnections and not common, continent wide prescriptions. **Response:** The fourth version of the proposed standard addresses the coordination issue many commenters expressed. Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning

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				Coordinator in the Functional Model Version 5.
Richard J Kafka	Potomac Electric Power Co.	1	Negative	PHI submitted comments
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.				
Francis J. Halpin	Bonneville Power Administration	5	Negative	Please see BPA's comments submitted during the formal comment period ending 7/17/10.
Rebecca Berdahl	Bonneville Power Administration	3	Negative	
Response: The SDT has made conforming changes to the proposed standard that address many of the concerns highlighted in the comments received during the third posting. Please see the revised standard.				
Ralph Frederick Meyer	Empire District Electric Co.	1	Negative	Prefer that a reliability standard requirement should to an entire entity class (per the Functional Model) not some sub-set of that entity. However, if the SDT determines to keep as indicated in this version, then we suggest that section 4 be revised to add clarity. Without the benefit of the background information above, the intent of the language in 4.2 and 4.3 could be lost. We suggest that section 4.2 be revised to read "UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment or automatic switching of Elements as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers" and that 4.3 be deleted.
Response: Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Owner; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding by the Transmission Owner (only). The switching of elements is generally performing at higher voltages than distribution voltages and as a result decided to not include the Distribution Providers in Requirement R10. This is the reason why the SDT did not merge Section 4 parts 4.2 and 4.3.				
Tim Hattaway	PowerSouth Energy Cooperative	5	Negative	R10 needs further clarification. One would assume that the "element" referred to is one that is essential to the correct function of the UFLS scheme?
Response: Commenters expressed that the wording in Requirement R10 "switching of elements" is confusing. The team modified Requirement R10 to clarify that it means: "switching of capacitor banks, Transmission Lines, and reactors" in order to control over voltage as a result of under frequency load shedding.				
Harold Taylor, II	Georgia Transmission Corporation	1	Negative	R3: Recommend diagrams to show the intended difference between 3.3.2 and 3.3.3. 3.3.2 should be "Generating Plants" (NO "/facilites") and 3.3.3 should be "Facilities". This would separate the combustion turbine or combined cycle generation which utilize common bus work from co-generation facilities that tie load and generation to a common utility substation bus.

Voter	Entity	Segment	Vote	Comment
				R5: What constitutes concurrence? 100% agreement? Can two or more Planning Coordinators with differing criteria reach a mutual agreement? R10: The use of upper case and lower case letters for emphasis can be confusing. What is the point of capitalizing "Elements"? Is it to imply switching a bulk load center from one island region to another and thus change the balance of generation to load in each island? Is the intent to enable or disable UF tripping for a given load center (substation) as it is transfered from one island region to another?
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters. No changes made. Commenters expressed that the wording in Requirement R10 “switching of elements” is confusing. The team modified Requirement R10 to clarify that it means: “switching of capacitor banks, Transmission Lines, and reactors” in order to control over voltage as a result of under frequency load shedding.				
Douglas E. Hils	Duke Energy Carolina	1	Negative	Requirements R5 and R13 contain the problematic requirement to “reach concurrence”, as discussed in our responses to the comment form. One way to address this concern would be to revise R5 and R13 to require affected Planning Coordinators to share design assessment results and event assessment results and respond to technical questions/comments within a prescribed time period.
Response: Many commenters suggested that the Reliability Assurer be assigned responsibility for coordinating UFLS activities and for reaching concurrence. In the third version of the standard Requirement R5 and R13 required concurrence between Planning Coordinators if an island encompassed more than on Planning Coordinator area. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.				
Tom Bowe	PJM Interconnection, L.L.C.	2	Negative	SDT must define “design assessment”. Is it different from every other one of the other assessments conducted by the PC? Without clarification an RE is left with these questions: Is the requirement to conduct an assessment? Or is it to conduct an assement that sucessfully meets R3? Is the PC non-compliant when its area’s assets can not resolve the studied condition? Additionally, R12 is unclear in what it means by “event actuation”. Is the objective to run an assessment; or is the objective to “design” a solution to islands created during a planning assessment. Clarify meaning of event actuation. R11 can be read to mean “when that event occurred in the real system (i.e. was actuated) then an event analysis must be considered; or it can mean when an assessment shows the creation of an island, then the PC must devise a process or procedure to correct the

Voter	Entity	Segment	Vote	Comment
				incident within 1 year. The text is awkward.
Response: The objective of the design assessment is to verify that the design of the UFLS program satisfies R3. For the purposes of PRC-006, the design assessment needs to be distinguished only from the event assessment, which is an after-the-fact analysis of a UFLS event per R11. There are no other assessments required by this standard. It is required to conduct an assessment that shows the UFLS program design satisfies R3 for each of the identified islands from R2. A PC would be non-compliant if its UFLS program cannot satisfy the performance curves in the Attachments up to a 25 percent imbalance between load and generation while considering the sub-points specified in R4. The objective of the event assessment is to analyze events after-the-fact. Event actuation is the time when the event was initiated. The point of R12 is to follow up after an event assessment if the event assessment indicated that the UFLS program did not perform as well as expected, or that improvements may be possible. It is not required that improvements be made, only considered. R11 means "when that event occurred in the real system (i.e. was actuated) then an event analysis must be considered." The PC does not need to "devise a process or procedure to correct the incident within 1 year," though a PC may consider changes to the UFLS program design that might improve its performance in future events of a similar nature in R12.				
Mark Ringhausen	Old Dominion Electric Coop.	4	Negative	See my comments in the VRF/VSL ballot.
Response: Please see our response to your comments in the consideration of comments report.				
Ronald D. Schellberg	Idaho Power Company	1	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. WECC had a disturbance the was negatively impacted by the lack of cordination of UFLS between subregions. Continent wide Frequency-time curves would not account for the interconnection size.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation.				
Laurie Williams	Public Service Company of New Mexico	1	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within a Reliability Region as there are Planning Coordinators. Additionally, the proposed standard does not address

Voter	Entity	Segment	Vote	Comment
				UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; “For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.				
Richard J. Padilla	Pacific Gas and Electric Company	5	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. The proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. The proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves

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				through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; “For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.				
William Mitchell Chamberlain	California Energy Commission	9	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model Version 5				

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and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; “For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.				
George R. Bartlett	Entergy Corporation	1	Negative	The following are the reasons associated with our Negative Ballot. Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. **Response:** Thank you for your support. In M3 it is unclear what action is intended by the phrase “including the criteria itself”. Since the criteria is specified in R3, it is recommended that the phrase be deleted. **Response:** The SDT agrees with the commenter and removed the phrase from both M2 and M3. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: “Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators.” We also recommend that the wording in R5 be changed to: “Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint.” **Response:** The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT’s proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT also made associated changes to the corresponding measures. The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. **Response:** The SDT made conforming changes to the VSL for Requirement R11. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. **Response:** The SDT does not agree with the recommendation to add a range of time to
Joel T Plessinger	Entergy	3	Negative	

Voter	Entity	Segment	Vote	Comment
				the VSLs. The SDT established increments in the VSLs according to NERC's VSL guidelines. We also recommend that the High and Severe VSLs that contain the phrase "shall conduct and document" to read "conducted and documented". The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) **Response:** The SDT accurately reflected the severity of not performing the study in the VSLs as proposed and does not agree that gradated the timeliness of the study is necessary. The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." **Response:** The SDT understands the concern with requiring entities to reach concurrence. The SDT redrafted Requirement R5 and Requirement R13 to address this concern. The SDT's proposal eliminates the need to reach concurrence and replaces it with clear required actions that demonstrate that the Planning Coordinators coordinated should an island cross Planning Coordinator areas. The SDT also made associated changes to the corresponding measures. We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information. The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the

Voter	Entity	Segment	Vote	Comment
				500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events. **Response:** The responsibility of generator owners resides within a standard under development currently, PRC-024. Per the implementation schedule, any requirements that necessitate the use of generator tripping data do not come into effect until after PRC-024 is approved.
John Canavan	NorthWestern Energy	1	Negative	The primary concern identified is that the current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. **Response:** Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; “For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	
John C. Collins	Platte River Power Authority	1	Negative	
Terry L Baker	Platte River Power Authority	3	Negative	
Glen Reeves	Salt River Project	5	Negative	

Voter	Entity	Segment	Vote	Comment
				A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided. **Response:** The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.
Jerome Murray	Oregon Public Utility Commission	9	Negative	The primary concern is that the current proposal does not require coordination within the interconnection. The standard should require the Planning Coordinators (PCs) within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are PCs. **Response:** The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE

Voter	Entity	Segment	Vote	Comment
				needs to be included in the Applicability section. **Response:** Several commenters indicated that LSEs should be included in the applicability of the standard. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided. **Response:** The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.

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Chad Bowman	Public Utility District No. 1 of Chelan County	1	Negative	The proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1 and 2. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT received many comments on prior versions of this standard to make sure PRC-006 was coordinated with PRC-024 as the two were being drafted. We are taking the direction of the majority of commenters.				
Jerry W Johnson	South Mississippi Electric Power Association	5	Negative	The requirement seems to require the installation of facilities rather than just relays. 16 USC 824o (a)(3) gives NERC the authority to regulate existing facilities and planned additions or modifications to those facilities, not to prompt or require modifications or additions to the existing facilities. Criteria are never actually defined in the requirements. Planning Coordinator footprints are not established. What does “annually maintain” mean? Does it mean the Database requires annual updates, annual reviews or just to provide a database annually? Frequency excursions precede an islanding event. I.e. low frequency initiates UFLS which should prevent an unintentional islanding event. The wording of this requirement makes it seem like the islanding event occurs first and causes the UF. Measures are too vague, lacking specifics, and not performance-based. This would leave too much up to the Auditor’s interpretation. Measures are only valuable if they contain specific targets or specifications that clarify how an entity will be deemed to be compliant with the standard as written. Measures which merely repeat the standard with the inclusion of “shall have evidence such as...” are not very useful. Measures should be explicit, detailed, consistent, and provide useful guidance to entities. These measures do not provide any useful guidance beyond what is specified in the requirement itself. M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that the phrase be deleted. M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. The graphical representation of the

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				frequency-time curves alone allows plenty of margin for mis-interpretation of the curves data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curves data points The standard lacks guidance as to what the trip settings should be. It is not clear as to how Attachment 1 should be used and doesn't provide specific detail for under frequency set points. Neighboring Planning Coordinators will be making requests and setting criteria for the local planning coordinators and associated UFLS entities. We do not agree with the text "any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating." It is not clear what is included in automatic switching. This requirement is so vague that it does not appear to add anything in addition to the UFLS program design that it is intended to address. It appears that anything that R10 may be designed to address is already covered by R9.
Response: TPL standards require addition of facilities under certain conditions. This standard is not out of line. The SDT disagrees that the jurisdiction of Planning Coordinators and their footprints has not been established. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. Annually maintain means annual updates, though not exclusively. UFLS cannot be expected to mitigate island formation. Most interconnections are large enough that a decline in frequency low enough to cause UFLS operations is highly unlikely unless the interconnection is broken into islands. Most UFLS operations are seen to occur following island formation. The SDT intends to add the performance characteristic curve data points. The under and over frequency performance curves are solely for checking dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points. UFLS entities are not affected, nor will a Planning Coordinator need to make requests of them or set criteria for them as far as island identification is concerned. The SDT believes the quoted text is necessary due to the wide range of island determination criteria (R1) that may be forthcoming. "Automatic switching of Elements" refers to switching of, among other Elements, cap banks to prevent excessive voltages. R10 has been modified to remove the confusion.				
Gregory J Le Grave	Wisconsin Public Service Corp.	3	Negative	The Standard is not ready for implementation because portions of the draft are difficult to interpret due to vague language. R5 and R13 use the phrase "reach concurrence". In addition, it isn't clear if the UFLS entities must have the Planning Coordinator's UFLS program implemented by the standard's effective date.
Response: The SDT agrees that reaching concurrence could be problematic and has modified R5 and R13 to address this concern. UFLS Entities only need to comply with the Planning Coordinator's schedule for application.				

Voter	Entity	Segment	Vote	Comment
Robert D Smith	Arizona Public Service Co.	1	Negative	The standard is too prescriptive. It requires that islands be formed and the underfrequency load shedding be designed to arrest the frequency in the islands and meet several requirements. While this is a valid approach, it is a very restricted and prescriptive approach. The islands formed in the study may not be the islands which actually form when the events happen. The under frequency load shedding scheme should be considered as a safety net and the Planning Coordinator should be given more flexibility. Most of the standard requirements should be guidelines.
Thomas R. Glock	Arizona Public Service Co.	3	Negative	
Mel Jensen	APS	5	Negative	
Dennis Sismaet	Seattle City Light	6	Negative	The standard, requirements, and measurements should reflect the uniqueness of the individual interconnections and not common, continent wide prescriptions.
Response: A continent-wide standard can specify performance curves or it can specify UFLS design parameters; the SDT has opted for performance curves. This is the less restrictive approach of the two. The standard does not require island formation, only identification of islands to be the basis for UFLS assessments. The standard does not require Planning Coordinators to predict islands that may occur in the future; it only requires criteria for island identification in order for the design assessments in R4 to be conducted. UFLS needs to arrest system frequency declines, whether as islands or the interconnection. Guidelines have no place in an enforceable standard. A continent-wide standard must identify requirements that are common to the four interconnections and the SDT believes the standard does that without being unnecessarily prescriptive.				
Michelle Rheault	Manitoba Hydro	1	Negative	This standard is not ready for ballot. See submitted comments.
Mark Aikens	Manitoba Hydro	5	Negative	
Daniel Prowse	Manitoba Hydro	6	Negative	
Response: Please see SDT responses on comment form.				
Jonathan Appelbaum	United Illuminating Co.	1	Negative	UI is voting negative because we believe EOP-003 should apply to manual load shed and uvls. The term load shed is easy to use but can mistakenly be interpreted to inculde automatic underfrequency load shed. Please see our comment form for futher clarifiction
Response: The EOP-003 SAR has very limited scope which allows removal of UFLS from EOP-003 and nothing else. UVLS remains in EOP-003 and another SDT has been assigned to EOP-003. The SDT is making a few other changes to EOP-003.				
James R. Keller	Wisconsin Electric Power Marketing	3	Negative	We agree with the Measures as far as the draft standard is currently written, however, see our comments for questions 11, 12, and 13 that would require modifications to requirements R9 & R10 and to M9 & M10. We agree with the Violation Severity Levels as far as the draft standard is currently written, however, see our comments for questions 11, 12, and 13 that would require modifications to requirements R9 & R10 and the corresponding Violation Severity Levels. Although we agree that the Planning Coordinator has the wide-area view and technical

Voter	Entity	Segment	Vote	Comment
Anthony Jankowski	Wisconsin Energy Corp.	4	Negative	skills to oversee the design of and ensure the effectiveness of a UFLS program, we are concerned with how this concept will actually play out, especially when a UFLS Entity is within multiple Planning Coordinators' footprints. We agree with the expanded scope of the supplemental SAR, however, EOP-003-1 needs further revision to focus this standard solely on manual loadshed. References to the development of both UFLS and UVLS programs need to be removed from EOP-003-1 as PRC-006-1 will cover automatic UFLS programs and a series of other PRC standards already cover automatic UVLS programs. The SDT should delete R2, R4, R7 and M1 from the posted SDT revised draft standard EOP-003-1 as part of supplemental SAR limited scope of revising requirements related to underfrequency loadshedding. In addition, the SDT should give consideration to inserting the word "manual" in front of the words "load shedding" in R3 and R5 in the posted SDT revised draft standard EOP-003-1. The Measures and Violation Severity Level sections would need to be updated accordingly. Although we agree with the intent of the revisions, EOP-003-1 needs further revision to focus this standard solely on manual loadshed.
Linda Horn	Wisconsin Electric Power Co.	5	Negative	References to the development of both UFLS and UVLS programs need to be removed from EOP-003-1 as PRC-006-1 will cover automatic UFLS programs and a series of other PRC standards already cover automatic UVLS programs. The SDT should delete R2, R4, R7 and M1 from the posted SDT revised draft standard EOP-003-1 as part of supplemental SAR limited scope of revising requirements related to underfrequency loadshedding. In addition, the SDT should give consideration to inserting the word "manual" in front of the words "load shedding" in R3 and R5 in the posted SDT revised draft standard EOP-003-1. The Measures and Violation Severity Level sections would need to be updated accordingly. We agree with the concept of using the frequency time performance curves instead of discrete points. However, we would like the SDT to provide additional technical background on the methodology utilized to develop both the underfrequency and overfrequency time performance curves beyond what was discussed in the "Review of Technical Changes to Standard" section in the preface of the "Unofficial Comment Form." We agree with the concept of using the PRC-024 generator underfrequency and overfrequency tripping curves instead of discrete points. In addition, we agree with the generator size and connection threshold clarification. However, we continue to believe that this standard places a burden on the UFLS Entity to shed additional load to make up for generators which do not conform to the PRC-006/PRC-024 curves. For example, if an independent power producer did not conform

Voter	Entity	Segment	Vote	Comment
				with the PRC-006/PRC-024 curves, it places a burden on the UFLS Entity to potentially have to shed additional load, up to the generator's rating, to make up for the non-conforming independent generator. Although we agree with the revision, we disagree with carrying forward the legacy concept of using an entire Regional Entity's footprint as an island. It is highly unlikely that the entire Regional Entity footprint would become an island. What is the technical justification for the continuation of the legacy concept of studying islands consisting of the entire Regional Entity's footprint? In addition, similar to the concurrence that the Planning Coordinators need to reach in R5, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: "The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets." Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R5, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: "The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission." Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Although we agree with the intent of this requirement, similar to the concurrence that the Planning Coordinators need to reach in R5 & R13, concurrence needs to be reached between the Planning Coordinator(s) and the Transmission Owner on the automatic switching of Elements in accordance with the UFLS program design and schedule for application. R10 needs to be revised as follows: "The Planning Coordinator(s) and each Transmission Owner shall reach concurrence on the automatic switching of Elements in accordance with the UFLS program design and schedule for application in each Planning Coordinator

Voter	Entity	Segment	Vote	Comment
				footprint in which the Transmission Owner owns transmission. Upon concurrence, each Transmission Owner shall provide automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission." Measurement M10 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Similar to the concurrence that the Planning Coordinators need to reach in R5 & R13, concurrence needs to be reached between the Planning Coordinator(s) and the UFLS Entity on the UFLS program design and schedule for application. R9 needs to be revised as follows: "The Planning Coordinator(s) and each UFLS entity shall reach concurrence on the UFLS program design and schedule for application in each Planning Coordinator footprint in which the UFLS entity owns assets. Upon concurrence, each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator footprint in which it owns assets." Measurement M9 needs to be revised to include the concurrence. The Data Retention and Violation Severity Level sections need to be updated accordingly. Although we agree with the intent of these requirements, the assessment required in R11 & R13 should only be completed for signif
Response: Please see SDT responses to questions 11, 12 and 13. The EOP-003 SAR has very limited scope which allows removal of UFLS from EOP-003 and nothing else. UVLS remains in EOP-003 and another SDT has been assigned to EOP-003. The SDT is making a few other changes to EOP-003. The over and under frequency versus time performance curves for UFLS were determined to coordinate with the Generator under and over frequency tripping curves (which have been also coordinated with the PRC-024 SDT) and to set a margin between the UFLS and generator curves. That is about all that can be said. The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. Requirement R2, Part 2.3 requires Regional Entity footprints to be identified as islands. Those islands are to be used in UFLS design assessments only, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. (The SDT agrees that there is no technical reason for designating Regional Entity footprints as islands.) The SDT has addressed the matter of GO versus TO/DP obligation for non-conforming generators and has decided that, for the likely small amount of non-conforming generation, that it should be a small burden, if any, to be spread across multiple TO sand DPs. Several other commenters have expressed concern with use of the term "concurrence" and the SDT has modified R5 and R13 to address those concerns by removing "concurrence." The SDT agrees that UFLS Entities should have opportunity to provide input to the Planning Coordinator on what will be required of them. R14 has now been added to the standard and requires a peer review of a Planning Coordinator's design and schedule for implementation by the UFLS Entities. Hopefully, this addresses, at least in part, the commenter's suggestions. PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009.				
Jason L	Midwest ISO, Inc.	2	Negative	We are voting negative because: 1) EOP-003 is posted in this standards action and was

Voter	Entity	Segment	Vote	Comment
Marshall				just balloted last week in the Order 693 directives project. It is not clear how the differences will be resolved. 2) The PC needs frequency characteristics of generators to comply with the standard but the GOs have no obligation to supply them. 3) While conceptually dynamic simulation to test the UFLS schemes is a good idea, it may not be practical. Dynamic simulation of these UFLS schemes involves extreme contingency analysis which stretches the limits of the simulation tools. 4) There is an arbitrary requirement to split islands based on regions.
Response: The EOP-003 conflict has been resolved. PRC-024 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. Dynamic simulations of UFLS performance, including disturbances initiating island formation, have been done in the past and the SDT does not believe they are impractical. There are a number of assumptions that go into UFLS studies, however, and so these studies should be undertaken by experienced planners. The intent of Requirement R2, Part 2.3 is to attempt to preserve the present regional coordination of UFLS plans and designs. Requirement R2, Part R2.3 requires Regional Entity footprints to be identified as islands. Those islands are to be used in UFLS design assessments only, and the Planning Coordinators within each Regional Entity footprint must work with each other on the design assessments for those islands (R5). The SDT believes that this goes as far as practical to address the need to coordination UFLS plans within a region. (The SDT agrees that there is no technical reason for designating Regional Entity footprints as islands.)				
Janelle Marriott	Tri-State G & T Association Inc.	3	Negative	We believe that individual Planning Coordinators are not the appropriate entities to be responsible for determining criteria for areas that may form islands, for identifying the islands, for developing the UFLS program for periodic assessments, for maintaining databases or for assessing events. The current registration by numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. All Planning Coordinators within an interconnection should be required to collaboratively develop an interconnection-coordinated UFLS Plan. Further, Planning Coordinator footprints are neither defined nor is there any guidance on how they should be established. Every VSL that refers to a PC footprint should be clarified. The primary purpose of any UFLS program should is to mitigate the need to form islands by balancing total system loads and resources. It is only a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding events rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not an individual island issue and therefore not driven by an individual PC but by a coordination of PCs efforts within the interconnection. We strongly believe that there should be recognized sub-area group(s), which consist of PCs, as assigned by the Regional Assurer (RA), which is the agent(s) for overall coordination within the interconnection or sub-area. For example in the WECC, the RA recognizes the following sub-area groups for UFLS coordination within the Interconnection: Southern Islanding Load Tripping, Northwest Power Pool UFLS Group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA

Voter	Entity	Segment	Vote	Comment
				assuring coordination of the sub-area groups, PCs could randomly or arbitrarily form sub-area groups whose plans do not coordinate or address the interconnection reliability needs There is also a concern that EOP-003-2 is currently being balloted based on changes made as a part of the Order 693 Directives. The two versions are not compatible. We believe that “ownership” should be removed from the criteria because it may be different from the operating or controlling entity and both entities cannot be responsible. Load Serving Entities should also be included as a “possible” UFLS entity. Some large interruptible customers outside of DP or TO could be allowed to own UFLS devices. Each interconnection should establish discrete set points based upon stability and dynamic analysis. From discrete set points one can establish criteria which are measurable and performance based for the applicable entities. The existing analysis tools available are unable to model continuous time/frequency curves and therefore specific measurements for all entities cannot be defined leaving the performance at the discretion of the PC. Furthermore, the Standard needs to be very explicit that the curves are interconnection performance curves and not specific protective relay set points. The standard should adequately recognize the performance characteristics of different type of generation and a variance should not be required. Faster acting and greater inertia systems should be allowed the operating margins appropriate to their systems. Real differences exist between interconnections. The standard and its performance requirements should reflect this fact. This would allow for the uniqueness of each interconnection to be addressed similar to Hydro Quebec’s variance.

Response: The SDT believes the Planning Coordinator, having a wide-area view and the necessary technical skills, is the proper entity to oversee the design and implementation of UFLS. There is also wide industry support for the Planning Coordinator as the proper entity for UFLS. The Reliability Assurer has a very limited scope of activity in the Functional Model and is not a user, owner or operator of the BES. The SDT recognizes the need to at least preserve coordination on the regional level and has inserted a requirement (Requirement R2, Part 2.3) to identify each Regional Entity footprint as an island to be assessed for UFLS performance. The PC’s within each region will need to work with each other in order to produce a successful assessment.

The SDT disagrees that the jurisdiction of Planning Coordinators and their footprints has not been defined or established. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities.

The SDT agrees that interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The standard does not preclude development of Regional UFLS standards and that approach may address WECC’s desire to have one coordinated UFLS design.

The SDT agrees that frequency is an interconnection issue, but also acknowledges that, should an island form, frequency becomes an island issue also. The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because most UFLS operations are seen to occur following island formation, not while a system remains interconnected.

LSEs are not an appropriate entity to implement UFLS because they do not own UFLS relays or switching equipment

The under and over frequency performance curves are solely for checking dynamic simulations of UFLS program performance and should not be misunderstood as applying to UFLS relay set points. Analysis tools do not need to model the performance characteristic curves; the curves are used to check frequency trajectories only. The PC’s UFLS program design must comply with these curves in simulated response so performance is not at the PC’s

Voter	Entity	Segment	Vote	Comment
discretion. A continent-wide standard can specify performance curves or it can specify UFLS design parameters; the SDT has opted for performance curves. This is the less restrictive approach of the two.				
Kathleen Goodman	ISO New England, Inc.	2	Negative	We believe that the applicability section, which states: UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers Excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This appears to be a missing link that needs to be addressed before the standard can be approved. Also, the standard is potentially in conflict with the work to be done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. This would present yet another example of lack of coordination on NERC Standards development.
Response: PRC-024 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. The SDT has coordinated with the PRC-024 SDT so that both PRC-006 and PRC-024 are using the same under and over frequency generator tripping curves. Note that the situation of data required by another standard exists elsewhere; for example, TPL standards compliance requires data from MOD standards.				
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Negative	We disagree with the inclusion of the curves at the end of the standard - Attachment 1. The curves may not be realistic depending on the topology of the BES in any particular area.
Response: The SDT acknowledges that UFLS programs shedding more than 25-30 percent of load may need to apply different UFLS performance characteristic curves, but these curves are realistic up to at least 25 percent of load. The SDT does not believe topology to be a relevant factor, except that topology may lead to the need to arm larger amounts of UFLS.				
Paul Rocha	CenterPoint Energy	1	Negative	With regards to the proposed PRC-006-1; CenterPoint Energy is concerned about the overly prescriptive nature of this proposal and cannot support it in its present form. In particular, a requirement to identify areas that “may Island” might, arguably, make sense for a large interconnection such as the eastern or western interconnect, but it makes no sense for a smaller interconnect such as ERCOT that, essentially, is already an island for the purposes of this standard. Even for the larger interconnections, there are limitless possibilities of potential “islands” that could occur given certain combinations of contingencies. Since it is impractical to identify every conceivable island, it is unclear what level of diligence and documentation would be required to demonstrate to an auditor’s satisfaction that the responsible entity has reasonably identified areas that “may” island. This ambiguity and subjectivity is contrary to objective number 2 in the Project Background to develop a standard “with clearly defined requirements and unambiguous language”.

Voter	Entity	Segment	Vote	Comment
Response: All that is required concerning island identification (R1, R2) is to devise some criteria considering historical events and system studies and use those criteria to identify some islands. This does not mean that every conceivable island must be identified. The criteria can be as simple or elaborate as a Planning Coordinator desires. The SDT does not believe this is overly prescriptive, nor does it believe that it is ambiguous. However, island identification is admittedly subjective and it is difficult to offer more specific guidance in the standard without limiting adaptability.				
Michael Ibold	Xcel Energy, Inc.	3	Negative	Xcel Energy believes that the standard still contains many issues that are not clear and need to be resolved. Among these issues is the mapping of PC to subordinate entities in areas where a regional entity or RTO has not taken on the PC role. Also, there are concerns around how small generators (less than the threshold specified) are addressed. Detailed comments were submitted to NERC with the concurrent comment period.
Response: Please see SDT response to these comments on the comment form. The SDT disagrees that the mapping of Planning Coordinators to subordinate entities is a significant issue. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. This standard does not apply to Generator Owners, but this SDT has coordinated on the development of PRC-024 with that SDT. Although this has long been a subject of debate, the SDT generally believes that generators smaller than the Statement of Compliance Registry thresholds can be omitted without significantly compromising reliability. GOs below the threshold could be registered if necessary for reliability according to the Compliance Registry Criteria.				
Liam Noailles	Xcel Energy, Inc.	5	Negative	Xcel Energy believes that the standard still contains many issues that are not clear and need to resolved. Among these issues is the mapping of PC to subordinate entities in areas where a regional entity or RTO has not taken on the PC role. Also, there are concerns around how small generators (less than the threshold specified) are addressed. Detailed comments were submitted to NERC with the concurrent comment period.
David F. Lemmons	Xcel Energy, Inc.	6	Negative	
Response: Please see SDT response to these comments on the comment form. The SDT disagrees that the mapping of Planning Coordinators to subordinate entities is a significant issue. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. This standard does not apply to Generator Owners, but this SDT has coordinated on the development of PRC-024 with that SDT. Although this has long been a subject of debate, the SDT generally believes that generators smaller than the Statement of Compliance Registry thresholds can be omitted without significantly compromising reliability. GOs below the threshold could be registered if necessary for reliability according to the Compliance Registry Criteria.				
Gregory L Pieper	Xcel Energy, Inc.	1	Negative	Xcel Energy believes the standard still contains many aspects that are not clearly understood by entities, including what is needed to demonstrate a compliant PSMP. Comments have been submitted concurrently to NERC via the draft comment response form.
Response: Please see SDT response to these comments on the comment form.				
Edward P. Cox	AEP Marketing	6	Affirmative	AEP has provided some general comments to the last posting.

Voter	Entity	Segment	Vote	Comment
Response: Please see SDT response to these comments on the comment form.				
David H. Boguslawski	Northeast Utilities	1	Affirmative	Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved. Also, the standard is potentially in conflict with the work being done on the Generator Verification Standard, which proposes to have Generator Performance during Frequency and Voltage Excursions contained in PRC-024. Sufficient coordination on NERC Standards development needs to occur on a going forward basis.
Response: PRC-024 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. The SDT has coordinated with the PRC-024 SDT so that both PRC-006 and PRC-024 are using the same under and over frequency generator tripping curves. Note that the situation of data required by another standard exists elsewhere; for example, TPL standards compliance requires data from MOD standards.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved. This standard seems to be contrary to FERC's stated concern with NPCC(Oct. 2009 Washington DC meeting) to develop a standard that can support the program it was designed to enforce.....the applicability as stated in the standard and by NERC registry criteria restricts and excludes the need for GO's that may in aggregate be necessary for a reliable UFLS program, to adhere to the standard. The standard also is potentially in conflict with the work being done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. Sufficient coordination on NERC Standards development needs to occur on a going forward basis.
Response: PRC-024 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. The SDT has coordinated with the PRC-024 SDT so that both PRC-006 and PRC-024 are using the same under and over frequency generator tripping curves. Note that the situation of data required by another standard exists elsewhere; for example, TPL standards compliance requires data from MOD standards.				
Saurabh Saksena	National Grid	1	Affirmative	At present, the proposed implementation plan language describes a one year phase-in period for compliance that is intended to provide the Planning Coordinators with

Voter	Entity	Segment	Vote	Comment
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Affirmative	sufficient time to (i) develop and/or modify UFLS programs; and, (ii) to establish an implementation plan for all required equipment changes. It must be recognized that any implementation plan would probably cover a multi-year period reflecting the time required to perform the engineering, purchasing, installation, and testing phases associated with implementing new and/or modified UFLS schemes. As an example, NPCC has already implemented a Region specific UFLS Program incorporating a six year UFLS implementation plan, with year one of the plan having ended June, 2010. As such, NPCC is concerned with how the final language included in the NERC UFLS implementation plan might impact the NPCC-specific UFLS Implementation Program. NPCC will closely monitor NERC's efforts in developing its UFLS Reliability Standard so NPCC can appropriately include the continued implementation of its Region specific UFLS Program within the NPCC Regional Standard PRC-006-NPCC-1, the required Regional Entity companion standard to the NERC UFLS Standard.
Response: The SDT believes that NPCC's six-year implementation plan will not be adversely affected by this standard or this standard's implementation plan.				
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Affirmative	Constellation Power Generation is voting affirmative in this ballot, however, there are still some issues with this project. Primarily, R10 appears to provide BWRs with some relief regarding compliance with the more restrictive UF trip setpoints; however, R7 and R8 are still applicable to them too. I think an auditor could look at R7 and R8 in isolation and say that BWRs may be in violation of those requirements. A potential fix may be to add the following text to R7 and R8 - "[S]ubject to the exceptions and provisions set forth in R10, ..." Another concern is that the title for Figure 1 lists R8, yet the figure applies to R7, R8, R9, and R10. Constellation Power Generation suggests adding the other relevant requirement #s.
Response: The SDT suspects the commenter's comments apply to a different standard.				
Thomas W. Richards	Fort Pierce Utilities Authority	4	Affirmative	Please consider clarifying R10. It's a bit unclear wheather this is pertaining to the switching of capacitor banks to prevent an overvoltage condition.
Response: Yes, "automatic switching of Elements" refers to switching of, among other Elements, cap banks. R10 has been modified to remove the confusion.				

Voter	Entity	Segment	Vote	Comment
Charles H Yeung	Southwest Power Pool	2	Affirmative	SPP votes in favor of the standard but directs the SDT to the ISO RTO Council comments submitted on the PRC-006 standards. We are concerned the generator owner/operators are not included as applicabile registered entities to this standard but understand there is a separate effort to develop generator owner/operator standards that could require them to provide UFLS data to Planning Coordinators. Absent that enforceable requirement, PCs could be subject to inappropriate violations if a GO fails to provide needed UFLS data. In order to move new standards forward that rely on other yet to be approved standards, NERC must take a sensible approach in enforcement of requirements if a violation is found to be caused by gaps in enforceable standards as mentioned.
Response: PRC-024 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006.				
Steven Grego	MEAG Power	3	Affirmative	The reference to "automatic switching of Elements" needs to be clarified. Does it mean that the TO needs to switch capacitor banks, or does it refer to the breakers equipped with UF relays? If it is referring to capacitor banks, is this applicable near major generation busses?
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Affirmative	
Response: Yes, “automatic switching of Elements” refers to switching of, among other Elements, cap banks. R10 has been modified to remove the confusion.				
Larry E Watt	Lakeland Electric	1	Affirmative	This standard requires regional (collaborative) effort, however; it does not assign regional responsibility.
Response: Requirements cannot be assigned to Regional Entities and enforced the same way as other requirements because Regional Entities are not users, owners or operators of the BES. The SDT believes that, and the industry widely supports, the Planning Coordinator is the best entity.				
Jeff Nelson	Springfield Utility Board	3	Abstain	SUB provided some responses on the Comment Form.
Response: See SDT responses on comment form.				

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for Under Frequency Load Shedding Reliability Standard

Prerequisite Approvals

With one exception, there are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Under Frequency Load Shedding standard and any associated regional reliability standards can be implemented. Parts 4.1 through 4.6 of Requirement R4 of the Under Frequency Load Shedding standard shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

Proposed Effective Date

Compliance with the new version PRC-006-1 — Underfrequency Load Shedding reliability standard (Requirements R1 through R14 with the exception noted above for Requirement R4, Parts 4.1 through 4.6) is effective one year following the first day of the first calendar quarter after applicable regulatory approvals.

The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time: 1) to develop, modify, or validate (to determine that the program meets performance characteristics) existing UFLS programs, and 2) to establish a schedule for implementation, or validate a schedule for completion of program revisions already in progress Transmission Owners and Distribution Providers shall comply with the schedule determined by the Planning Coordinator but no sooner than the effective date of the standard.

Compliance with the revised EOP-003-1 — Load Shedding Plans reliability standard is effective one year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

Applicability

Certain requirements within the proposed standard are intended to apply only to entities that own or operate UFLS relays. These requirements would not apply to other entities. The drafting team has designated these entities that own or operate UFLS relays as "UFLS Entities." They may include the following:

- Transmission Owners
- Distribution Providers

For decades underfrequency load shedding programs have been implemented by different entities depending on how the transmission system was constructed and owned. In some parts of the country, Distribution Providers accomplished this task, in others it was the Transmission Owners. Indeed, the set of standards intended to be replaced by this new standard allowed either of these registered entities, along with others in some cases, to accomplish the task of owning and operating UFLS relays. Because of this historical nature of the entities involved in the implementation of UFLS programs, and as listed in the applicability listed in the standards PRC-007-0 and PRC-009-0 that this standard is intended to replace, each of the functions listed above will have a role in implementing UFLS programs.

Retired Standards

The following standards will be retired when PRC-006-1 becomes effective:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-009-0 — UFLS Performance Following an Underfrequency Event will be completely retired once PRC-006-1 becomes effective as specified above.

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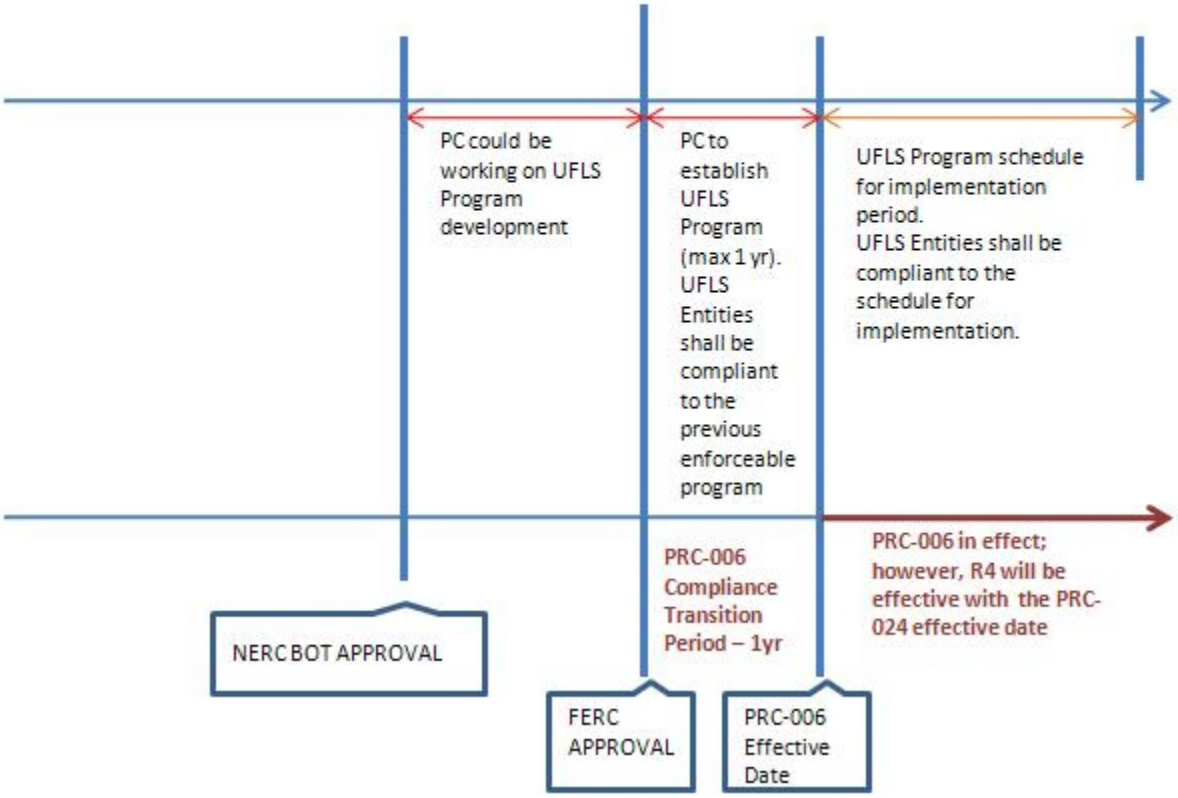
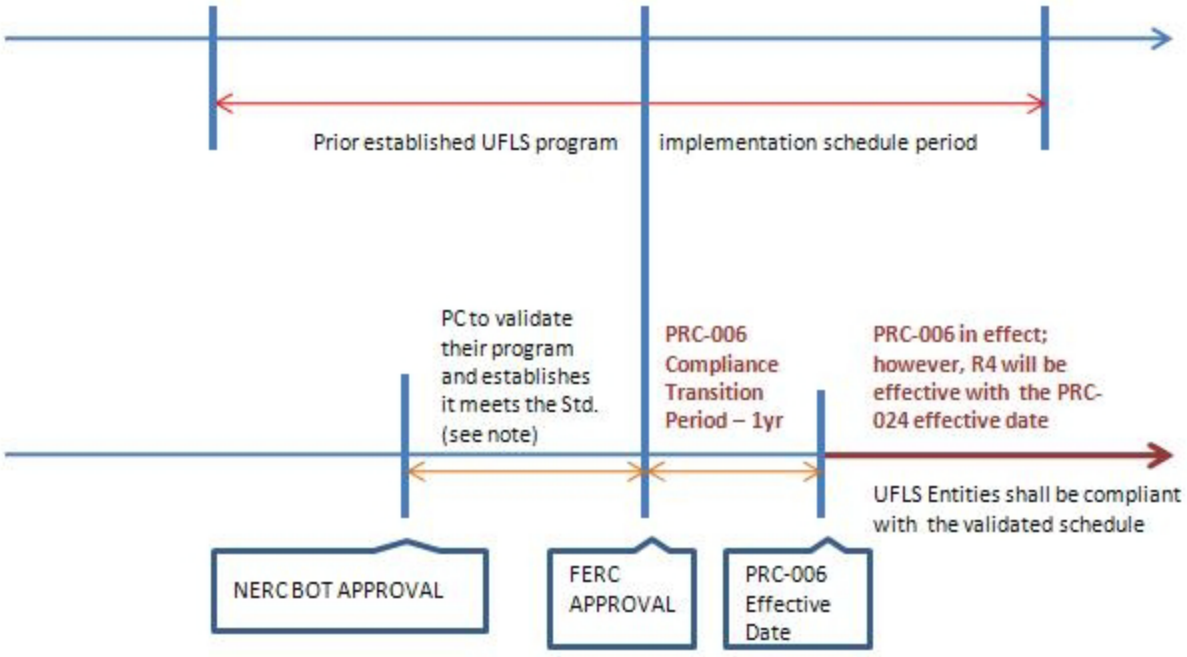
UFLS Timeline Example 1

(No Existing program)



UFLS Timeline Example 2

(Existing UFLS program)



Note: If the PC determines that their program is not valid to the standard, PC will need to follow Timeline Example 1.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for PRC-006-1 — Under Frequency Load Shedding Reliability Standard

Prerequisite Approvals

With one exception, there are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Under Frequency Load Shedding standard and any associated regional reliability standards can be implemented. Parts 4.1 ~~and~~ through 4.6~~2~~ of Requirement R4 of the Under Frequency Load Shedding standard shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

Proposed Effective Date

Compliance with the new version PRC-006-1 — Underfrequency Load Shedding reliability standard (Requirements R1 through R14 with the exception noted above for Requirement R4, ~~p~~Parts 4.1 through 4.6) is effective one year following the first day of the first calendar quarter after applicable regulatory approvals ~~(or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required)~~.

The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time: 1~~-~~) to develop, ~~,or~~ modify, or validate (to determine that the program meets performance characteristics) existing ~~-~~UFLS programs and 2~~-~~) to establish a schedule for implementation, or validate a schedule for completion of program revisions already in progress~~.~~ Transmission Owners and Distribution Providers shall comply with the schedule determined by the Planning Coordinator but no sooner than the effective date of the standard.

Compliance with the revised EOP-003-1 — Load Shedding Plans reliability standard is effective one year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

Applicability

Certain requirements within the proposed standard are intended to apply only to entities that own or operate UFLS relays. These requirements would not apply to other entities. The drafting team has designated these entities that own or operate UFLS relays as "UFLS Entities." They may include the following:

- Transmission Owners
- Distribution Providers

For decades underfrequency load shedding programs have been implemented by different entities depending on how the transmission system was constructed and owned. In some parts of the country, Distribution Providers accomplished this task, in others it was the Transmission Owners. Indeed, the set of standards intended to be replaced by this new standard allowed either of these registered entities, along with others in some cases, to accomplish the task of owning and operating UFLS relays. Because of this historical nature of the entities involved in the

implementation of UFLS programs, and as listed in the applicability listed in the standards PRC-007-0 and PRC-009-0 that this standard is intended to replace, each of the functions listed above will have a role in implementing UFLS programs.

Retired Standards

The following standards will be retired when PRC-006-1 becomes effective:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-009-0 — UFLS Performance Following an Underfrequency Event will be completely retired once PRC-006-1 becomes effective as specified above.

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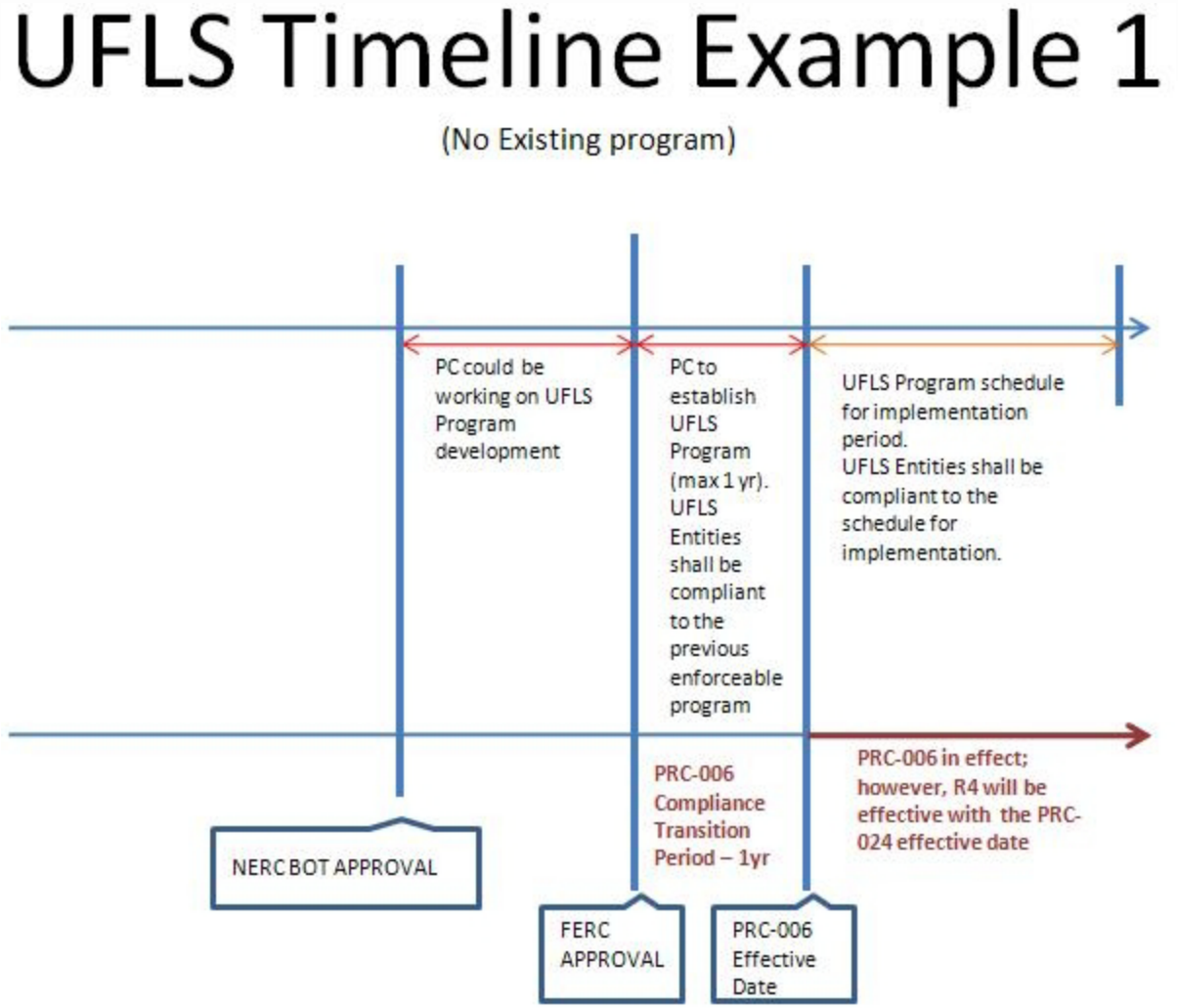
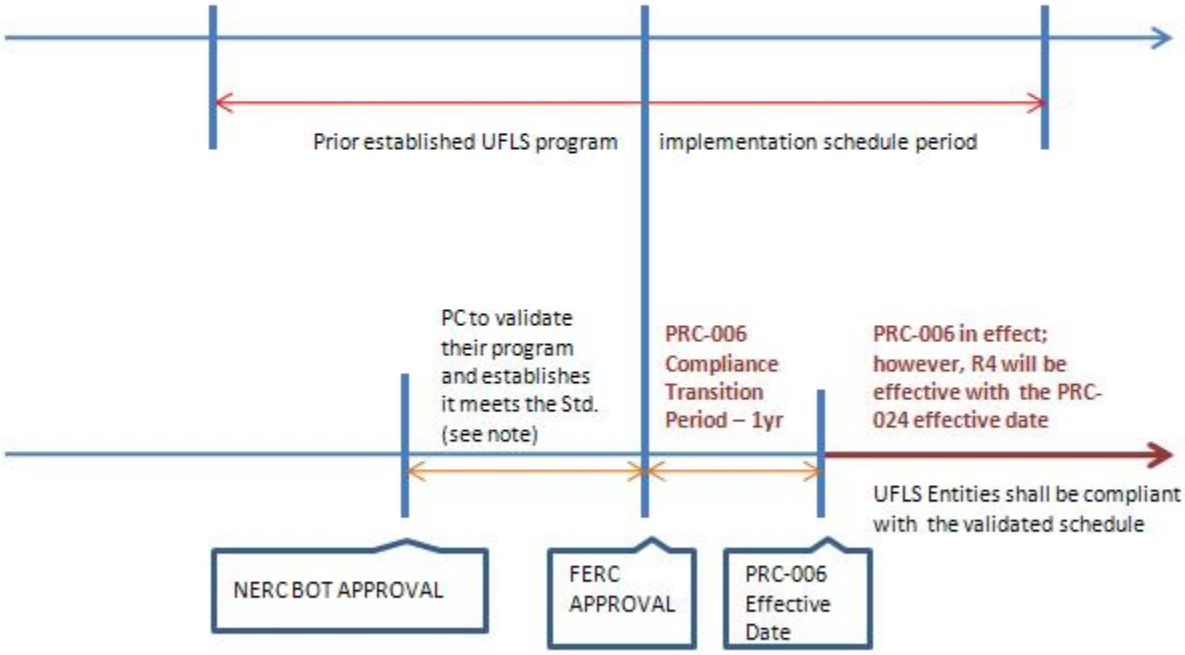

UFLS Timeline Example 1
(No Existing program)
PC could be working on UFLS Program development
PC to establish UFLS Program (max 1 yr). UFLS Entities shall be compliant to the previous enforceable program
UFLS Program schedule for implementation period.
UFLS Entities shall be compliant to the schedule for implementation.
PRC-006 Compliance Transition Period – 1yr
PRC-006 in effect; however, R4 will be effective with the PRC-024 effective date
NERC BOT APPROVAL
FERC APPROVAL
PRC-006 Effective Date

UFLS Timeline Example 2

(Existing UFLS program)



Note: If the PC determines that their program is not valid to the standard, PC will need to follow Timeline Example 1.

A. Introduction

1. **Title:** **Load Shedding Plans**

2. **Number:** EOP-003-1

3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date:** One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions

R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

M1. Each Transmission Operator that has or directs the deployment of undervoltage load shedding facilities, shall have and provide upon request, its automatic load shedding plans. (Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring Period and Reset Timeframe

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
R2	N/A	N/A	N/A	The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.
R3.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
R4.	N/A	N/A	N/A	The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.
R5.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.
R6.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
R7.	The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.
R8.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	TBD	Modified R4, R5, R6	Revised to eliminate redundancies with PRC-006-1

A. Introduction

1. **Title:** **Load Shedding Plans**

2. **Number:** EOP-003-1

3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date:** One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R1/R3 - Because these requirements are is related to manual load shedding in addition to automatic load shedding, the drafting team did not modify the requirement. The UFLS standard is a planning standard and proposes requirements for automatic UFLS programs.

R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.

R2 - The SDT reviewed R2 and thinks the original intent is to allow the TOP and BA to have a UFLS OR a UVLS program. If UFLS is deleted the original intent is modified such that the TOP has to have a UVLS program. This is why the SDT decided to add the additional language to the requirement. BA was deleted from the requirement because they are not responsible for voltage.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.

R4 – The BA was deleted from the requirement because they are not responsible for voltage and references to items to consider for UFLS were deleted.

R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions

R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

R7- The BA was deleted from the requirement because it is not responsible for voltage and "undervoltage" was added in the requirement because the TOP will have UFLS in its area and it should not be responsible for coordinating.

C. Measures

M1. Each Transmission Operator that has or directs the deployment of undervoltage load shedding facilities, shall have and provide upon request, its automatic load shedding plans.(Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring Period and Reset Timeframe

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
R2	N/A	N/A	N/A	The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.
R3.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
R4.	N/A	N/A	N/A	The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.
R5.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
R7.	The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.
R8.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	TBD	Modified R4, R5, R6	Revised to eliminate redundancies with PRC-006-1

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on November 21, 2006.
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting Team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard, and posts for comments on April 15, 2009.

Proposed Action Plan and Description of Current Draft:

This is the second ballot period of the proposed standard.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. TBD	

A. Introduction

1. Title: **Automatic Underfrequency Load Shedding**

2. Number: PRC-006-1

3. Purpose: To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. Applicability:

4.1. Planning Coordinators

4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

4.2.1 Transmission Owners

4.2.2 Distribution Providers

4.3 Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. (Proposed) Effective Date:

5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.

5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

B. Requirements

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island

R3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance

scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 2, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R5. Each Planning Coordinator shall coordinate its UFLS program design with all other affected Planning Coordinators for each island identified by any one Planning Coordinator that encompasses all or a portion of its Planning Coordinator area through the following action(s): *[VRF: Medium][Time Horizon: Long-term Planning]*

5.1. Conduct a UFLS design assessment for each island modeling all UFLS programs in the island

5.2. In the event the UFLS design assessment in Requirement R5, Part 5.1 fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report the recommended modifications to UFLS program(s) to the affected Planning Coordinator(s) and the ERO

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. [VRF: Lower Time Horizon: Long-term Planning]

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

R10. Each Transmission Owner shall provide automatic switching of capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which it owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

R13. Each Planning Coordinator, in whose area a BES islanding event affecting multiple Planning Coordinator areas and resulting in system frequency excursions below the initializing set points of the UFLS program, shall coordinate with the other affected Planning Coordinators on the

event assessment through the following action(s): *[VRF: Medium][Time Horizon: Operations Assessment]*

13.1. Conduct a UFLS event assessment for each island modeling all UFLS programs in the island

13.2. In the event the UFLS event assessment in Requirement R13, Part 13.1 fails to coordinate with the event assessment of other Planning Coordinator(s), each Planning Coordinator shall identify differences in the assessments that likely resulted in the differences in the event assessment results and report these differences to the affected Planning Coordinators and the ERO.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Low][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2 Parts 2.1 through 2.3.

M3. Each Planning Coordinator shall have evidence such as reports, program plans, or other documentation of its UFLS program including the implementation schedule that meet the criteria in Requirement R3 Parts 3.1 through 3.3.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4 Parts 4.1 through 4.7.

M5. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation demonstrating its UFLS design assessment; including, if necessary to meet the performance characteristics in Requirement R3, modifications to the UFLS program(s) and supporting documentation such as memorandums, letters, or other dated documentation that it notified the other affected Planning Coordinators and the ERO of any necessary design changes, for any islands identified by a Planning Coordinator that encompass all or a portion of its Planning Coordinator area per Requirement R5.

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it annually maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6.

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding in accordance with the UFLS program and schedule for application per Requirement R10.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

M12. If UFLS program deficiencies are identified in R11, each Planning Coordinator shall have dated evidence that it conducted a UFLS design assessment per Requirements R12 and R4.

M13. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation demonstrating its UFLS event assessment; including, if necessary supporting dated documentation such as memorandums, letters and other dated documentation identifying differences in event assessments between Planning Coordinators, to demonstrate that event assessments of multiple Planning Coordinators in an affected island are coordinated or to show the reasons why the assessment results are different per Requirement R13.

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.

- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11 and R13, Measures M11 and M13, for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands
R2	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3 OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.
R3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by	The Planning Coordinator developed a UFLS program including a schedule for implementation by	The Planning Coordinator developed a UFLS program including a schedule for implementation by

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions	UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions	UFLS entities within its area, but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2
R5	N/A	N/A	N/A	The Planning Coordinator failed to conduct and document a UFLS assessment for any island identified by any one Planning Coordinator that encompasses all or a portion of its

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Planning Coordinator area. OR The Planning Coordinator failed to notify all other affected Planning Coordinators and the ERO of UFLS design changes necessary to meet the performance characteristics in Requirement R3 for any island identified by any one Planning Coordinator that encompasses all or a portion of its Planning Coordinator area.
R6	N/A	N/A	N/A	The Planning Coordinator failed to annually maintain a UFLS database for use in event analyses and assessments of the UFLS program.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.		The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which it owns transmission	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which it owns transmission	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which it owns transmission	The Transmission Owner provided less than 85% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which it owns transmission
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 greater than one year	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 greater than 13	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 greater than 14

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		but less than or equal to 13 months of actuation.	months but less than or equal to 14 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement R11, Parts11.1 or 11.2.	months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event affecting multiple Planning Coordinator areas and resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document a UFLS assessment. OR The Planning Coordinator, in whose area a BES islanding event affecting multiple Planning Coordinator areas and resulting in system frequency excursions below the initializing set points of the UFLS program, failed to notify all other affected Planning Coordinators and the ERO of differences between UFLS event assessment and reasons for those differences.
R14	The Planning Coordinator did not respond to all the written comments but to more than 90% of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.	The Planning Coordinator responded to 90% or less but more than 80% of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.	The Planning Coordinator responded to 80% or less but more than 70% of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.	The Planning Coordinator responded to 70% or less of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.

E. Regional Variances

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E3.1 Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, and

E3.2 Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 2A, and

E3.3 Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E3.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

E3.3.2 Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

E3.3.3 Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

E4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

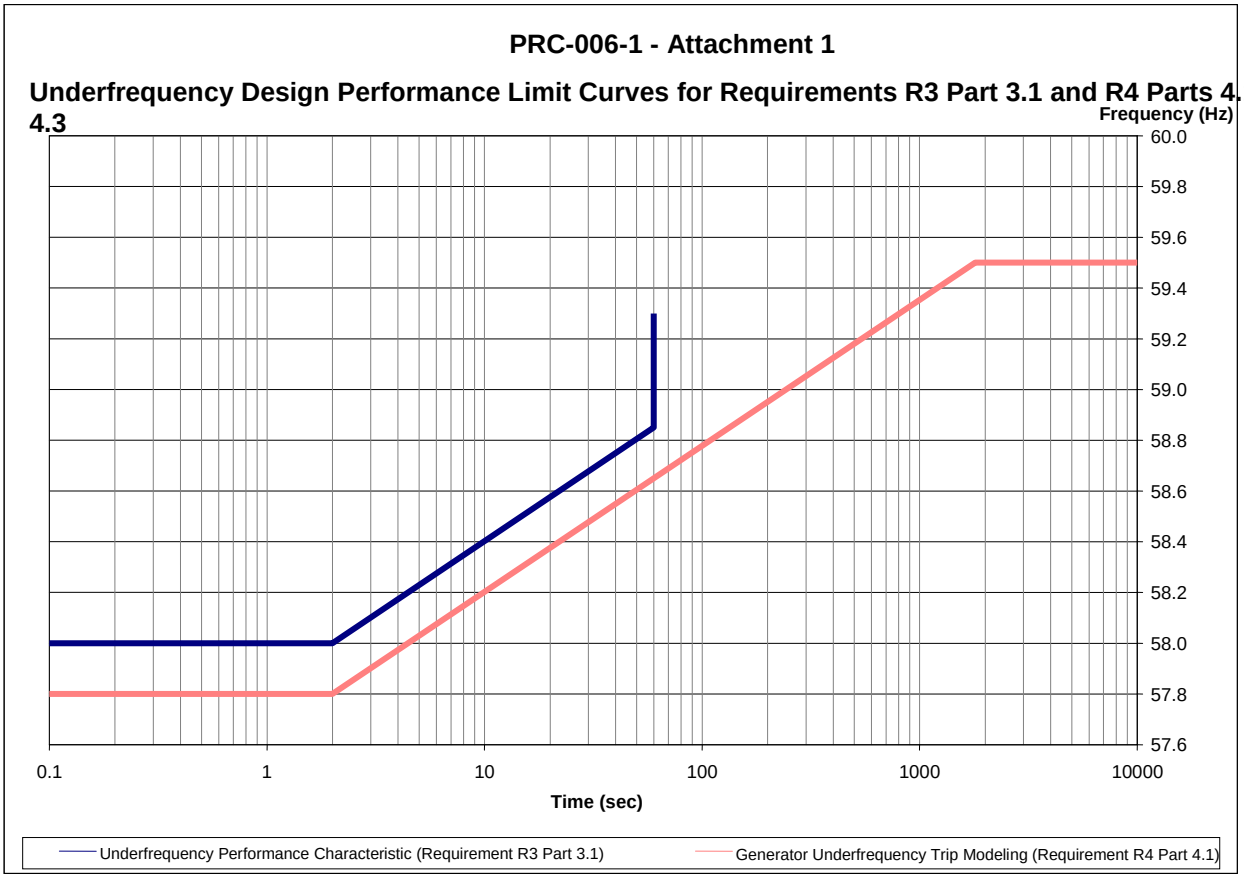
E4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

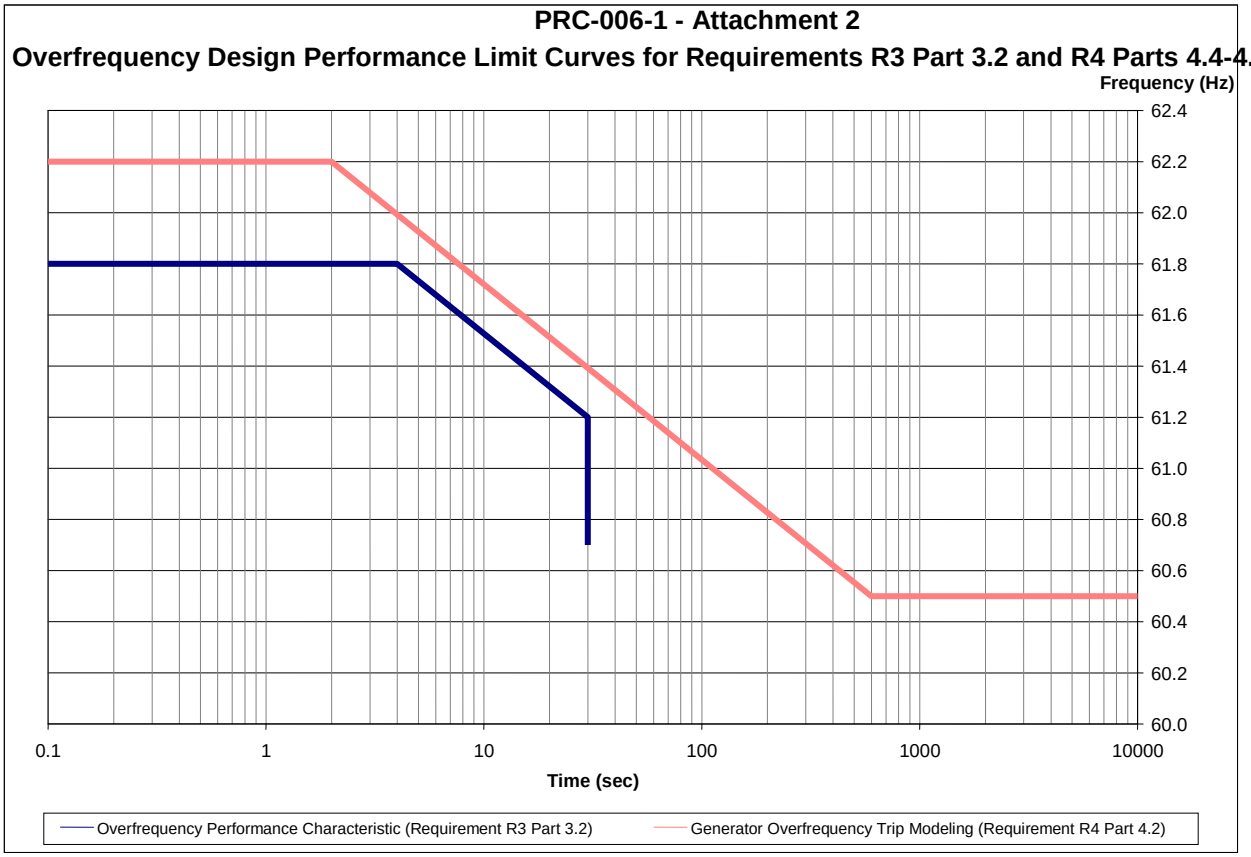
V #	Lower VSL	Moderate VSL	High VSL	Severe VSL
VE3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E3.1, E3.2, or E3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E3.1, E3.2, or E3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E3.1, E3.2, and E3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
VE4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include one (1) of the items as specified in Parts E4.1, E4.2 or E4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E4.1, E4.2 or E4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E4.1, E4.2 and E4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3

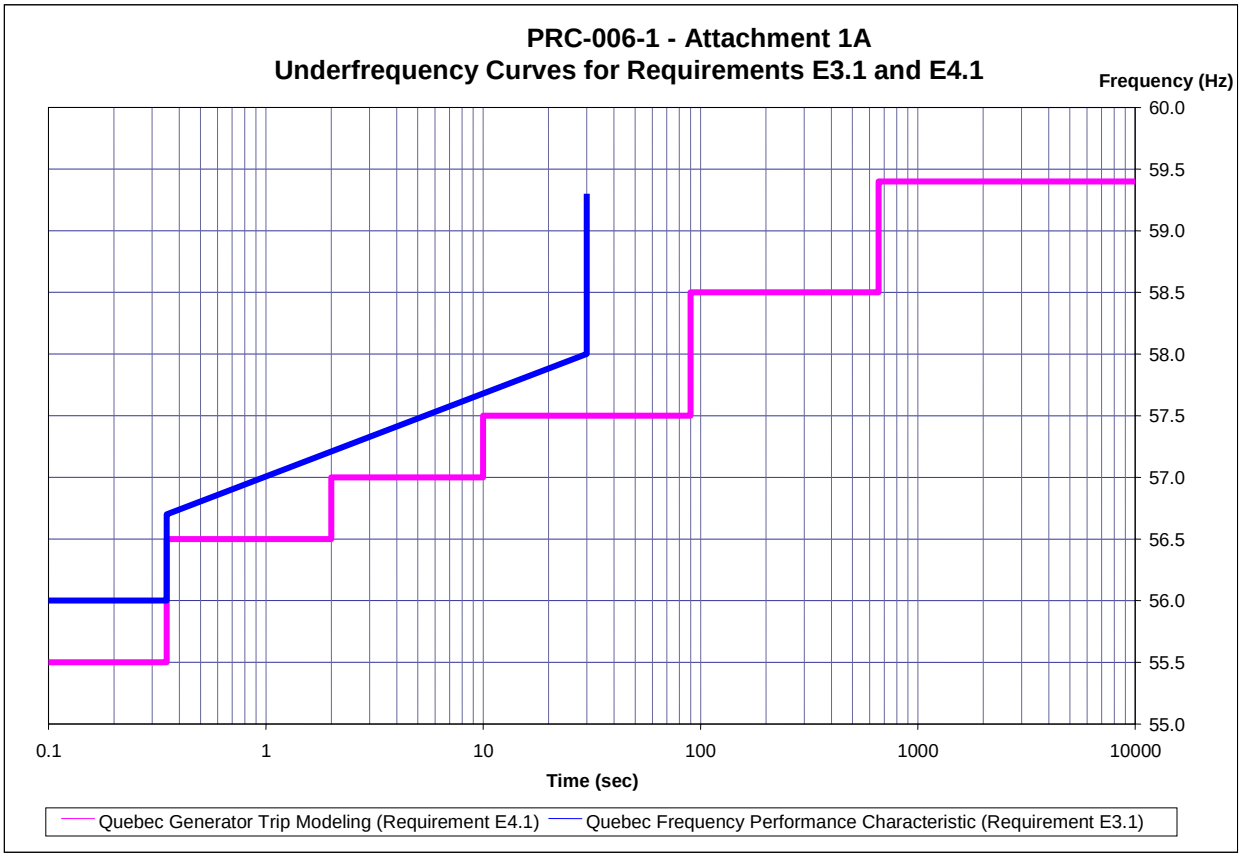
F. Associated Documents

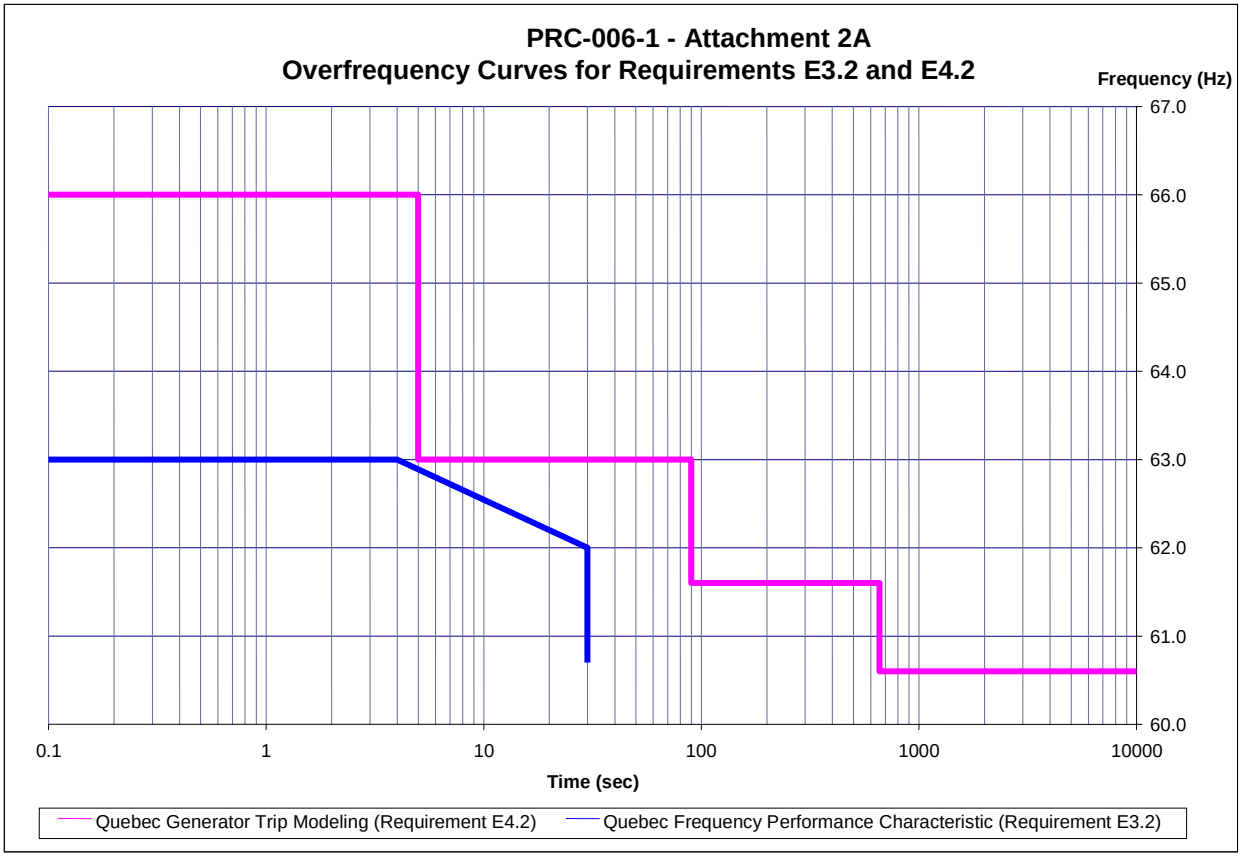
Version History

Version	Date	Action	Change Tracking
1		Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0	


PRC-006-1 - Attachment 1
Underfrequency Design Performance Limit Curves for Requirements R3 Part 3.1 and R4 Parts 4.1 - 4.3
Frequency (Hz)
60.0
59.8
59.6
59.4
59.2
59.0
58.8
58.6
58.4
58.2
58.0
57.8
57.6
0.1
1
10
100
1000
10000
Time (sec)
Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
Generator Underfrequency Trip Modeling (Requirement R4 Part 4.1)


PRC-006-1 - Attachment 2
Overfrequency Design Performance Limit Curves for Requirements R3 Part 3.2 and R4 Parts 4.4-4.6
Frequency (Hz)
62.4
62.2
62.0
61.8
61.6
61.4
61.2
61.0
60.8
60.6
60.4
60.2
60.0
0.1
1
10
100
1000
10000
Time (sec)
Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
Generator Overfrequency Trip Modeling (Requirement R4 Part 4.2)


PRC-006-1 - Attachment 1A
Underfrequency Curves for Requirements E3.1 and E4.1
Frequency (Hz)
60.0
59.5
59.0
58.5
58.0
57.5
57.0
56.5
56.0
55.5
55.0
0.1
1
10
100
1000
10000
Time (sec)
Quebec Generator Trip Modeling (Requirement E4.1)
Quebec Frequency Performance Characteristic (Requirement E3.1)


PRC-006-1 - Attachment 2A
Overfrequency Curves for Requirements E3.2 and E4.2
Frequency (Hz)
67.0
66.0
65.0
64.0
63.0
62.0
61.0
60.0
0.1
1
10
100
1000
10000
Time (sec)
Quebec Generator Trip Modeling (Requirement E4.2)
Quebec Frequency Performance Characteristic (Requirement E3.2)

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on November 21, 2006.
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting Team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard, and posts for comments on April 15, 2009.

Proposed Action Plan and Description of Current Draft:

This is the ~~third posting of the proposed standard~~second ballot period of the proposed standard.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. TBD	

A. Introduction

1. Title: **Automatic Underfrequency Load Shedding**

2. Number: PRC-006-1

3. Purpose: To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. Applicability:

4.1. Planning Coordinators

4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

4.2.1 Transmission Owners

4.2.2 Distribution Providers

4.3 Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. (Proposed) Effective Date:

5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals ~~(or the standard otherwise becomes effective the first day of the first calendar quarter one year after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required)~~.

~~5.~~5.2. Parts 4.1 ~~and~~ through 4.6 of Requirement R4 ~~of the Under Frequency Load Shedding standard~~ shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

B. Requirements

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator ~~footprints~~ areas and Regional Entity ~~footprints~~ areas that may form islands. *[VRF: ~~Lower~~Medium][Time Horizon: Long-term Planning]*

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity ~~footprint~~area or the Interconnection in which the Planning Coordinator's ~~footprint~~area resides. If a Planning Coordinator's ~~footprint~~area resides in multiple Regional Entity ~~footprint~~areas, each of those Regional Entity ~~footprint~~areas shall be identified as an island

R3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its ~~footprint~~area that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

The purpose of the Underfrequency and Overfrequency Design Performance Limit Curves in PRC-006-1 Attachments 1 and 2 is to define a performance boundary that island system frequency should not cross during the UFLS program design simulation. Together, these curves provide a level of coordination between each Planning Coordinator's Underfrequency Load Shed program and between these programs and generator under and overfrequency ride-through capability.

~~Frequency shall remain between the Under and Over Frequency Performance Characteristic curves in PRC-006-1 - Attachment 1 either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached.~~

~~3.2.~~3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

~~3.3.~~3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 2, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for

each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.3. -Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 2.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

~~**R5.** Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion for any islands identified by any one Planning Coordinator that encompass more than one Planning Coordinator footprint. *[VRF: Medium][Time Horizon: Long-term Planning]*~~

R5. Each Planning Coordinator shall coordinate its UFLS program design with all other affected Planning Coordinators for ~~any~~each island~~s~~ identified by any one Planning Coordinator ~~that includes portions of more than one Planning Coordinator area~~ that encompasses all or a portion of ~~their~~its Planning Coordinator area through the following ~~set of~~ action(s): *[VRF: Medium][Time Horizon: Long-term Planning]*

5.1. C~~c~~onduct a UFLS design assessment for each island modeling all UFLS programs in the island

5.2. I~~i~~n the event the -UFLS design assessment in Requirement R5, Part 5.1 fails to meet Requirement R3, ~~the Planning Coordinator will~~ identify modifications to the UFLS program(s) ~~in order~~ to meet Requirement R3 and report the recommended

modifications to UFLS program(s) to the affected Planning Coordinator(s) -and the ERO

R6. Each Planning Coordinator shall ~~annually~~ maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. [VRF: Lower Time Horizon: Long-term Planning]

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator ~~footprint~~area~~area~~ in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

R10. Each Transmission Owner shall provide automatic ~~switching of Elements~~switching of capacitor banks, Transmission Lines, and reactors ~~in order~~ to control over-voltage as a result of under-frequency load shedding in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator ~~footprint~~area in which it owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

R11. Each Planning Coordinator, in whose ~~footprint~~area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

R13. Each Planning Coordinator, in whose ~~footprint~~area a BES islanding event affecting multiple Planning Coordinator ~~footprint~~areas and resulting in system frequency excursions below the initializing set points of the UFLS program ~~of UFLS actuated loss of load occurs~~, shall ~~reach concurrence~~coordinate with the other affected Planning Coordinators on the event assessment ~~results before event assessment completion~~through the following action(s):~~.~~ *[VRF: Medium][Time Horizon: Operations Assessment]*

13.1. Conduct a UFLS ~~design~~event assessment for each island modeling all UFLS programs in the island

13.2. In the event the UFLS ~~design~~event assessment in Requirement R13, Part 13.1 fails to coordinate with the event assessment of other Planning Coordinator(s), each Planning Coordinator shall identify differences in the assessments that likely resulted in the differences in the event assessment results and report these differences to the affected Planning Coordinators and the ERO. ~~meet Requirement R3, the Planning Coordinator will identify modifications to the UFLS program(s) in order to meet Requirement R3 and report the recommended modifications to UFLS program(s) to the affected Planning Coordinator(s) and the ERO~~

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Low][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2 Parts 2.1 through 2.3 ~~including the criteria itself~~.

M3. Each Planning Coordinator shall have evidence such as reports, program plans, or other documentation of its UFLS program including the implementation schedule that meet the criteria in Requirement R3 Parts 3.1 through 3.3 ~~including the criteria itself~~.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4 Parts 4.1 through 4.7.

M5. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation demonstrating its UFLS design assessment; including, if necessary to meet the performance characteristics in Requirement R3, modifications to the UFLS program(s) and supporting documentation such as memorandums, letters, or other dated documentation that it notified the other affected Planning Coordinators and the ERO of any necessary design changes, ~~memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results~~ for any islands identified by a Planning Coordinator that encompass all or a portion of ~~their~~its

Planning Coordinator area ~~more than one Planning Coordinator footprintarea~~ per Requirement R5. ~~and identifies the affected Planning Coordinators.~~

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it annually maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6.

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic ~~switching of Facilities~~ switching of capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of under-frequency load shedding in accordance with the UFLS program and schedule for application per Requirement R10.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

M12. If UFLS program deficiencies are identified in R11, each Planning Coordinator shall have dated evidence that it conducted a UFLS design assessment per Requirements R12 and R4.

M13. Each Planning Coordinator shall have dated ~~have~~ evidence such as reports, dynamic simulation models and results, or other dated documentation demonstrating its UFLS ~~design~~event assessment; including, if necessary supporting dated documentation such as memorandums, letters and other dated documentation identifying differences in event assessments between Planning Coordinators, to demonstrate that event assessments of multiple Planning Coordinators in an affected island are coordinated or to show the reasons why the assessment results are different ~~to meet the performance characteristics in Requirement R3, modifications to the UFLS program(s) and supporting documentation such as memorandums, letters, or other dated documentation that it notified the other affected Planning Coordinators and the ERO of any necessary design changes, letters, memorandums, or other dated documentation showing that each affected Planning Coordinator reached concurrence on the event assessment results~~ per Requirement R13.

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

~~**M13.**~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, ~~and~~ R12, and R14, Measures M1, M2, M3, M4, M5, ~~and~~ M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11 and R13, Measures M11 and M13, for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator ~~footprints~~ areas and Regional Entity ~~footprints~~areas, that may form islands OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator ~~footprints~~ areas and Regional Entity ~~footprints~~areas, that may form islands	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator ~~footprints~~ areas and Regional Entity ~~footprints~~areas, that may form islands	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator ~~footprints~~ areas and Regional Entity ~~footprints~~areas, that may form islands
R2	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3 OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				program.
R3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its ~~footprint~~area, but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its ~~footprint~~area, but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its ~~footprint~~area, but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Requirement R3 for each island identified in Requirement R2
R5	N/A	N/A	N/A	The Planning Coordinator failed to conduct and document a UFLS assessment for any island~~s~~ identified by any one Planning Coordinator that encompasses all or a portion of its Planning Coordinator area. OR The Planning Coordinator failed to ~~reach concurrence with~~notify all other affected Planning Coordinators and the ERO of~~n~~ UFLS design ~~assessment~~ changes necessary to meet the performance characteristics in Requirement R3 ~~results before design assessment completion~~ for any island~~s~~ identified by any one Planning Coordinator that encompasses all or a portion of ~~their~~its Planning Coordinator area~~that encompass more than one Planning Coordinator footprint.~~.
R6	N/A	N/A	N/A	The Planning Coordinator failed to annually maintain a UFLS database for use in event analyses and assessments of the UFLS program.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	30 calendar days and up to and including 40 calendar days following the request.	40 calendar days but less than and including 50 calendar days following the request.	50 calendar days but less than and including 60 calendar days following the request.	60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) ~~footprint~~area in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) ~~footprint~~area in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) ~~footprint~~area in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) ~~footprint~~area in which it owns assets.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator ~~footprint~~area in which it owns transmission	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator ~~footprint~~area in which it owns transmission	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator ~~footprint~~area in which it owns transmission	The Transmission Owner provided less than 85% automatic switching of Elements in accordance with the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator ~~footprint~~area in which it owns transmission
R11	~~Each~~ The Planning Coordinator, in whose ~~footprint~~area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, ~~shall~~ conducted and documented an assessment of the event within one year of event actuation. ~~to evaluate~~	The Planning Coordinator, in whose ~~footprint~~area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose ~~footprint~~area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 greater than 13 months but less than or equal to 14 months of actuation. OR The Planning Coordinator, in whose ~~footprint~~area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement R11, Parts ~~-~~11.1 or 11.2.	The Planning Coordinator, in whose ~~footprint~~area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 greater than 14 months of actuation. OR The Planning Coordinator, in whose ~~footprint~~area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose ~~footprint~~area an islanding

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				event resulting in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose ~~footprint~~ area a BES islanding event affecting multiple Planning Coordinator ~~footprints~~ areas and resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document a UFLS assessment. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator, in whose ~~footprint~~area a BES islanding event affecting multiple Planning Coordinator ~~footprints~~areas and resulting in system frequency excursions below the initializing set points of the UFLS program, failed to notify all other affected Planning Coordinators and the ERO of differences between UFLS ~~design~~event assessment and reasons for those differences ~~changes necessary to meet the performance characteristics in Requirement R3. reach concurrence with the other affected Planning Coordinators on the event assessment results before event assessment completion.~~
R14	The Planning Coordinator did not respond to all the written comments but to more than 90% of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.	The Planning Coordinator responded to 90% or less but more than 80% of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.	The Planning Coordinator responded to 80% or less but more than 70% of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.	The Planning Coordinator responded to 70% or less of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.

E. Regional Variances

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its ~~footprint~~area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E3.1 Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, and

E3.2 Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 2A, and

E3.3 Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E3.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

E3.3.2 Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

E3.3.3 Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

E4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

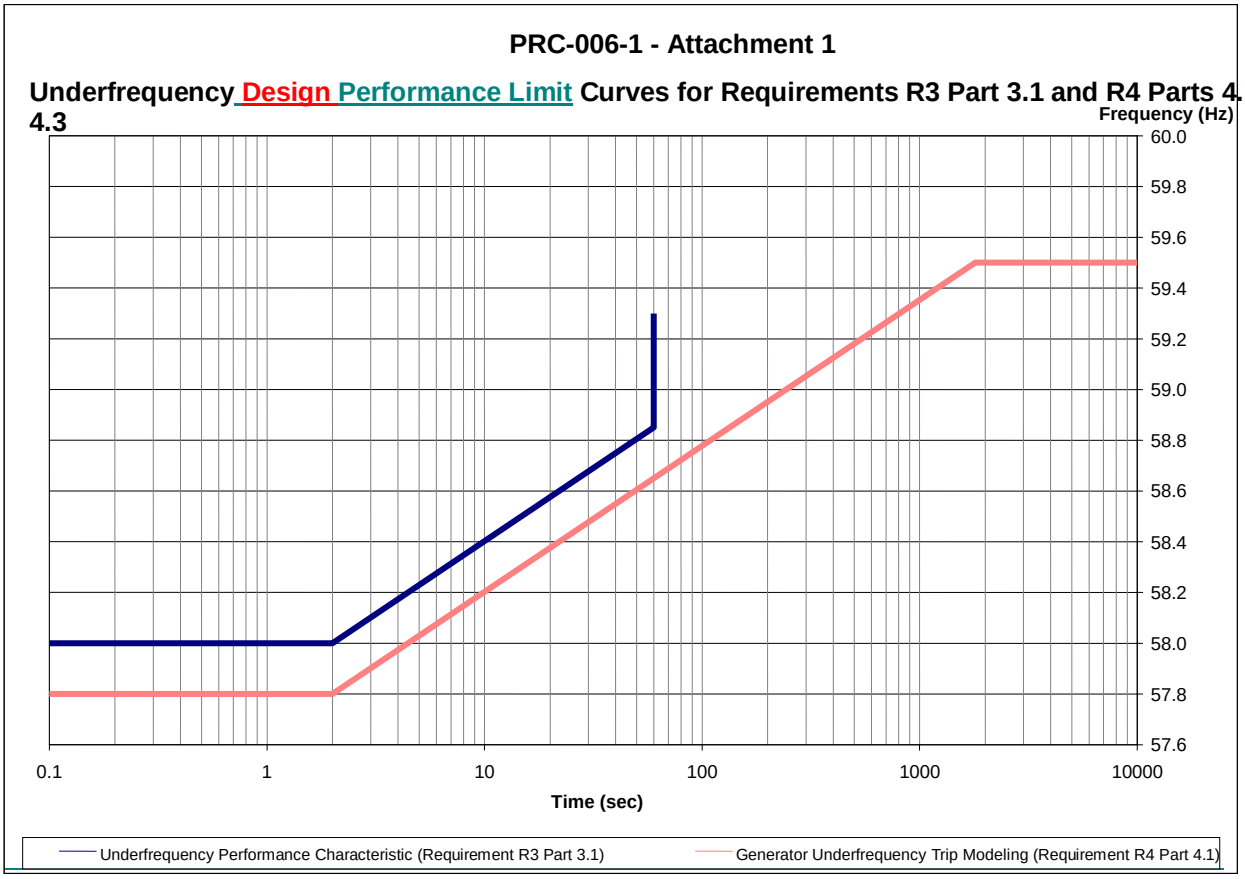
E4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

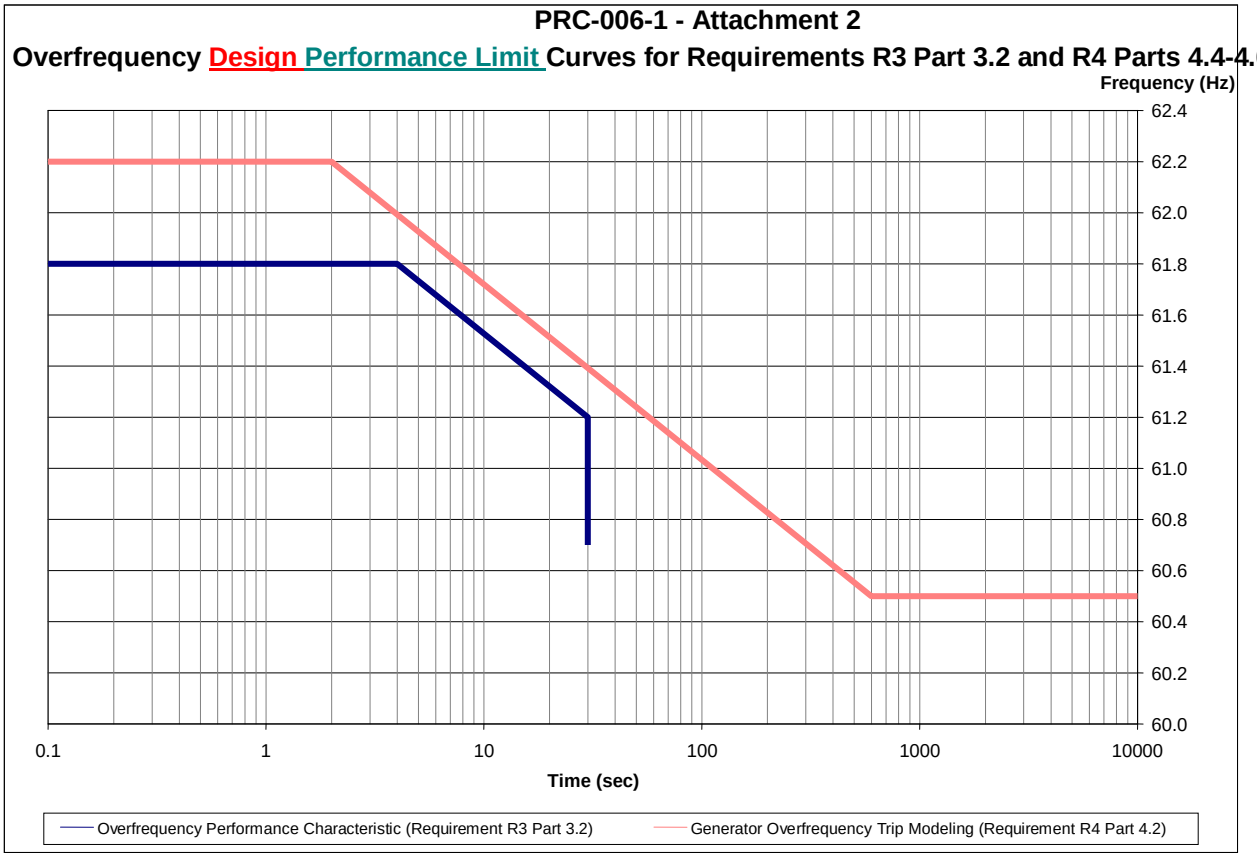
V #	Lower VSL	Moderate VSL	High VSL	Severe VSL
VE3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its ~~footprint~~area, but failed to meet one (1) of the performance characteristic in Parts E3.1, E3.2, or E3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its ~~footprint~~area, but failed to meet two (2) of the performance characteristic in Parts E3.1, E3.2, or E3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its ~~footprint~~area, but failed to meet all the performance characteristic in Parts E3.1, E3.2, and E3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
VE4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include one (1) of the items as specified in Parts E4.1, E4.2 or E4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E4.1, E4.2 or E4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E4.1, E4.2 and E4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3

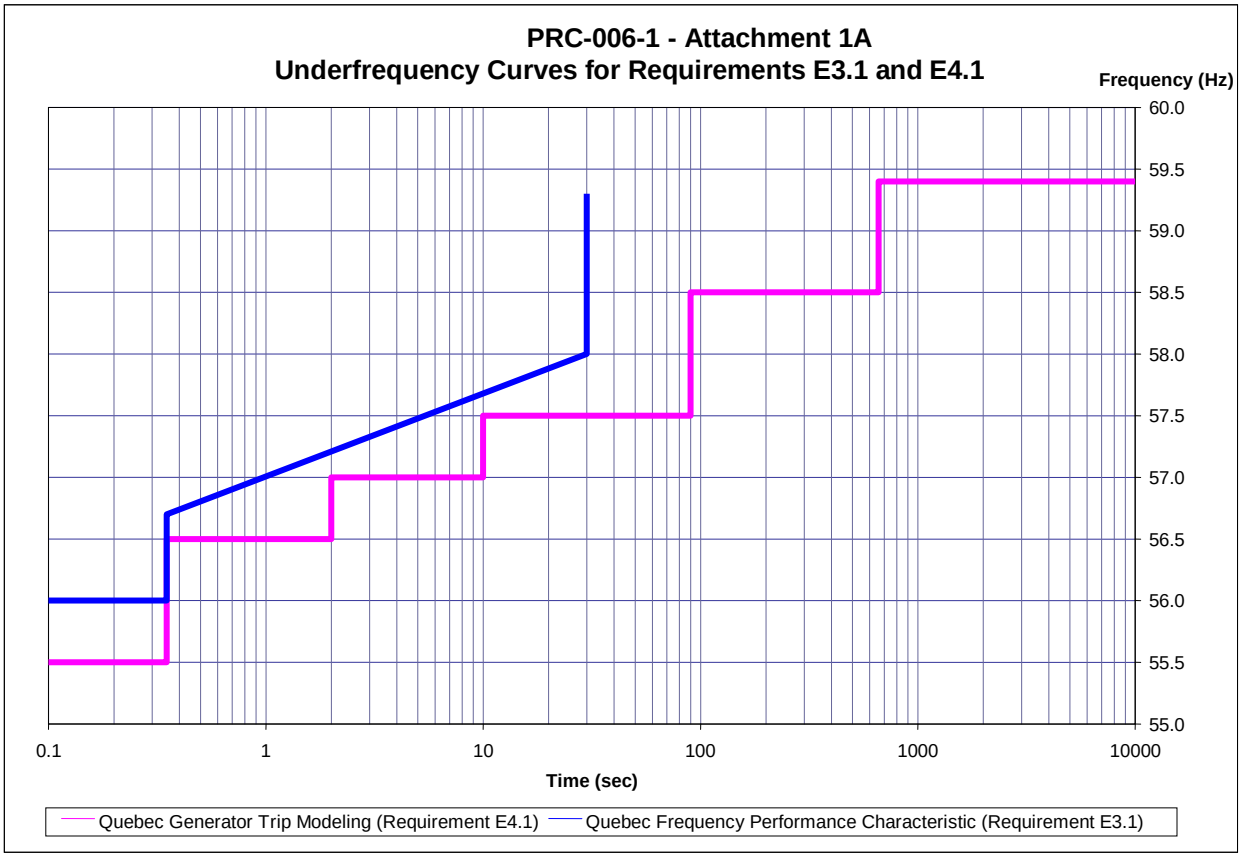
F. Associated Documents

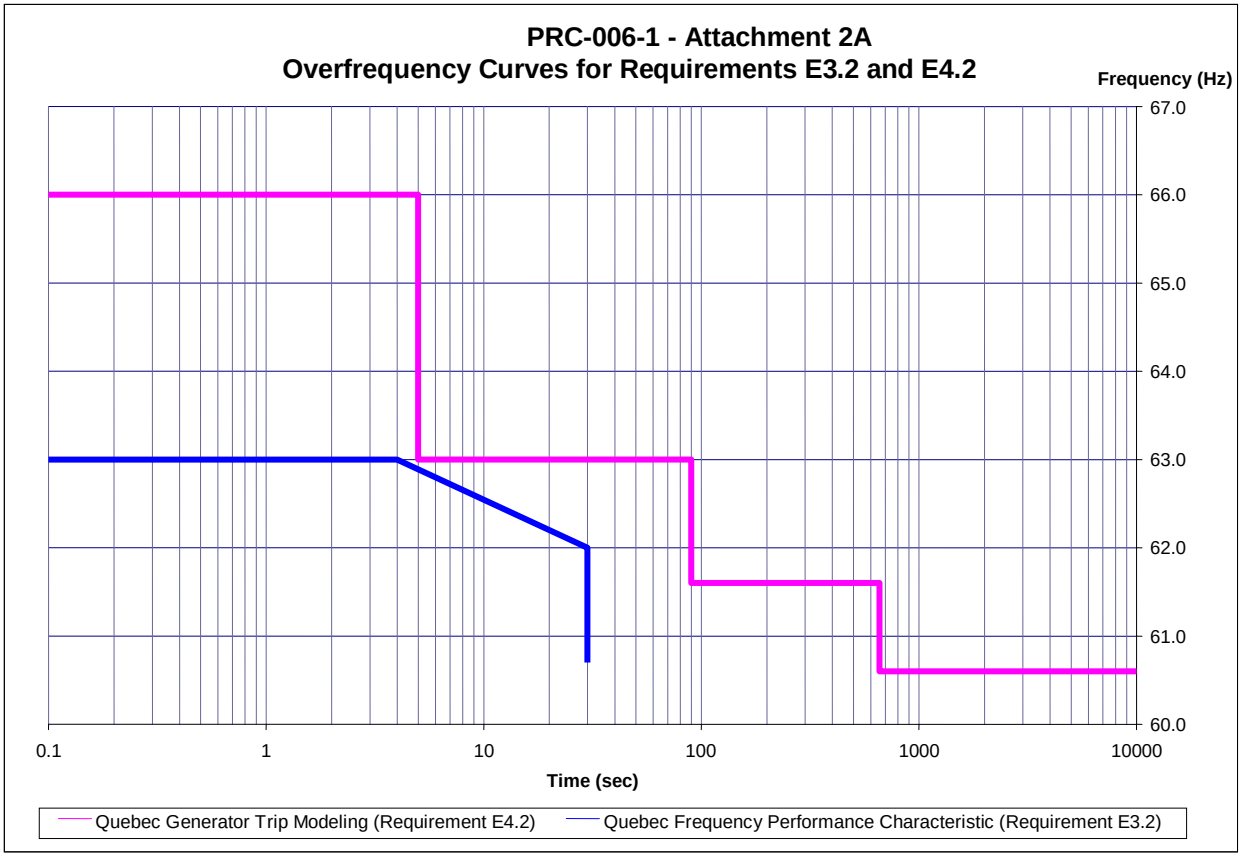
Version History

Version	Date	Action	Change Tracking
1		Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0	


PRC-006-1 - Attachment 1
Underfrequency Design Performance Limit Curves for Requirements R3 Part 3.1 and R4 Parts 4.1 - 4.3
Frequency (Hz)
60.0
59.8
59.6
59.4
59.2
59.0
58.8
58.6
58.4
58.2
58.0
57.8
57.6
0.1
1
10
100
1000
10000
Time (sec)
Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
Generator Underfrequency Trip Modeling (Requirement R4 Part 4.1)


PRC-006-1 - Attachment 2
Overfrequency Design Performance Limit Curves for Requirements R3 Part 3.2 and R4 Parts 4.4-4.6
Frequency (Hz)
62.4
62.2
62.0
61.8
61.6
61.4
61.2
61.0
60.8
60.6
60.4
60.2
60.0
0.1
1
10
100
1000
10000
Time (sec)
Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
Generator Overfrequency Trip Modeling (Requirement R4 Part 4.2)


PRC-006-1 - Attachment 1A
Underfrequency Curves for Requirements E3.1 and E4.1
Frequency (Hz)
60.0
59.5
59.0
58.5
58.0
57.5
57.0
56.5
56.0
55.5
55.0
0.1
1
10
100
1000
10000
Time (sec)
Quebec Generator Trip Modeling (Requirement E4.1)
Quebec Frequency Performance Characteristic (Requirement E3.1)


PRC-006-1 - Attachment 2A
Overfrequency Curves for Requirements E3.2 and E4.2
Frequency (Hz)
67.0
66.0
65.0
64.0
63.0
62.0
61.0
60.0
0.1
1
10
100
1000
10000
Time (sec)
Quebec Generator Trip Modeling (Requirement E4.2)
Quebec Frequency Performance Characteristic (Requirement E3.2)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Second Ballot Window Open Soon

July 24–August 3, 2010

Available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2007-01: Underfrequency Load Shedding

A second ballot window for proposed standards PRC-006-1 — Automatic Underfrequency Load Shedding and EOP-003-1— Load Shedding Plans will open on Saturday, July 24, 2010 and will remain open **until 8 p.m. Eastern on August 3, 2010.**

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Recirculation Ballot Process

The Standards Committee encourages all members of the ballot pool to review the consideration of comments submitted with the initial ballots and those submitted through the formal comment period. In this second ballot, votes are counted by exception only — if a ballot pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

Major objectives:

1. Ensure UFLS programs are developed to provide an appropriate level of reliability (not least common denominator).
2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.
3. Address the issues raised by FERC Order 693 and other applicable orders.
4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

The request and interpretation are posted on the project page:
http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Results

Ballot Name:	Project 2007-01 Underfrequency Load Shedding_rc
Ballot Period:	7/24/2010 - 8/3/2010
Ballot Type:	recirculation
Total # Votes:	292
Total Ballot Pool:	314
Quorum:	**92.99 % The Quorum has been reached**
Weighted Segment Vote:	49.61 %
Ballot Results:	**The Standard has NOT Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	89	1	32	0.421	44	0.579	7	6
2 - Segment 2.	9	0.7	1	0.1	6	0.6	2	0
3 - Segment 3.	76	1	34	0.548	28	0.452	8	6
4 - Segment 4.	26	1	11	0.5	11	0.5	1	3
5 - Segment 5.	57	1	21	0.438	27	0.563	5	4
6 - Segment 6.	36	1	12	0.414	17	0.586	6	1
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.5	4	0.4	1	0.1	1	1
9 - Segment 9.	7	0.6	4	0.4	2	0.2	0	1
10 - Segment 10.	7	0.7	5	0.5	2	0.2	0	0
Totals	**314**	**7.5**	**124**	**3.721**	**138**	**3.78**	**30**	**22**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Avista Corp.	Scott Kinney	Negative	View
1	Baltimore Gas & Electric Company	John J. Moraski	Abstain	

1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge	Negative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	CenterPoint Energy	Paul Rocha	Negative	View
1	Central Maine Power Company	Brian Conroy	Abstain	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Commonwealth Edison Co.	Daniel Brotzman	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	View
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Negative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Negative	View
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	View
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	View
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lake Worth Utilities	Walt Gill	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	Metropolitan Water District of Southern California	Ernest Hahn	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	View
1	Nebraska Public Power District	Richard L. Koch		
1	New York Power Authority	Arnold J. Schuff	Negative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	View
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Negative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Negative	View
1	PacifiCorp	Mark Sampson		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	Frank F. Afranji	Negative	View
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Negative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	View
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Negative	View
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Sacramento Municipal Utility District	Tim Kelley	Negative	View
1	Salt River Project	Robert Kondziolka		
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Negative	View

1	Seattle City Light	Pawel Krupa	Negative	View
1	Sierra Pacific Power Co.	Richard Salgo	Negative	View
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Negative	View
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	View
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Abstain	
1	Southwestern Power Administration	Gary W Cox	Abstain	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Jason L. Murray	Abstain	
2	BC Transmission Corporation	Faramarz Amjadi	Negative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Abstain	
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Negative	View
2	Southwest Power Pool	Charles H Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blachly-Lane Electric Co-op	Bud Tracy	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson	Negative	View
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Negative	
3	Entergy	Joel T Plessinger	Negative	View
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	View
3	Hydro One Networks, Inc.	Michael D. Penstone	Abstain	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Abstain	View
3	Los Angeles Department of Water & Power	Kenneth Silver		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	

3	Manitoba Hydro	Greg C Parent		
3	MEAG Power	Steven Grego	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	View
3	Muscatine Power & Water	John S Bos	Affirmative	
3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	View
3	North Carolina Municipal Power Agency #1	Denise Roeder	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Negative	
3	OTP Wholesale Marketing	Bradley Tollerson	Negative	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Negative	
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	View
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Negative	View
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	View
3	Salt River Project	John T. Underhill		
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	South Mississippi Electric Power Association	Gary Hutson	Negative	
3	Southern California Edison Co.	David Schiada	Negative	View
3	Springfield Utility Board	Jeff Nelson	Abstain	View
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	
3	Tri-State G & T Association Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	View
4	American Municipal Power - Ohio	Kevin Koloini	Negative	
4	American Public Power Association	Allen Mosher	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Oklahoma Municipal Power Authority	Terri Pyle	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	View
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Negative	View
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	View
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
4	Y-W Electric Association, Inc.	James A Ziebarth	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Negative	View
5	BC Hydro and Power Authority	Clement Ma	Negative	View

5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	Chelan County Public Utility District #1	John Yale	Negative	View
5	City of Grand Island	Jeff Mead	Negative	View
5	City of Tallahassee	Alan Gale	Negative	View
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	Duke Energy	Robert Smith	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	
5	Entergy Corporation	Stanley M Jaskot	Negative	View
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	JEA	Donald Gilbert	Abstain	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	View
5	Kissimmee Utility Authority	Mike Blough	Abstain	
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Negative	
5	Otter Tail Power Company	Stacie Hebert	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	View
5	PPL Generation LLC	Mark A Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Negative	View
5	Salt River Project	Glen Reeves	Negative	View
5	Seattle City Light	Michael J. Haynes	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones		
5	South Mississippi Electric Power Association	Jerry W Johnson	Negative	View
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	
5	Tri-State G & T Association Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	Cleco Power LLC	Matthew D Cripps	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	View
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Negative	View
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Negative	
6	Exelon Power Team	Pulin Shah	Negative	
6	FirstEnergy Solutions	Mark S Travaglianti	Negative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	

6	Florida Municipal Power Pool	Thomas E Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	View
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	View
6	Louisville Gas and Electric Co.	Daryn Barker	Abstain	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Abstain	
6	OTP Wholesale Marketing	Bruce Glorvigen	Negative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	View
6	RRI Energy	Trent Carlson	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	South Carolina Electric & Gas Co.	Matt H Bullard	Negative	View
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Negative	
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	View
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Abstain	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Negative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Negative	View
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Negative	View
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Second Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2007-01: Underfrequency Load Shedding

The second ballot for proposed standards PRC-006-1 — Automatic Underfrequency Load Shedding and EOP-003-1— Load Shedding Plans ended on August 3, 2010.

Ballot Results

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 92.99 %
Approval: 49.61 %

Next Steps

The drafting team will review and respond to the comments received, and will determine whether to make additional changes to the standard or its implementation plan, based on those comments. Should the team decide to make revisions the revised item(s) will be posted for a 30-day comment period with another ballot conducted during the last ten days of that comment period.

Project Background

Major objectives:

1. Ensure UFLS programs are developed to provide an appropriate level of reliability (not least common denominator).
2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.
3. Address the issues raised by FERC Order 693 and other applicable orders.
4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

More information is available on the project page:
http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Standards Development Process

For this project, the Standards Committee authorized using the standard development process in the *Standard Processes Manual*. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria (from *Standard Processes Manual*)

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, at least one more ballot must be conducted. If the drafting team makes no substantive changes following the initial ballot, then a "recirculation" ballot is conducted – however if the drafting team makes substantive changes, the revised standard (or definition) must be posted for a 30-day comment period, with a successive ballot conducted during the last 10 days of that comment period. If the drafting team does not make substantive changes following the successive ballot, then the standard moves forward to a recirculation ballot.

Consideration of Comments on Second Ballot — Project 2007-01 Underfrequency Load Shedding
Date of Ballot: 07/24/10 - 08/03/10

Summary Consideration:

- Comments received during the second ballot expressed confusion over the actual application of the curves in the Attachment to the standard. Several commenters indicated that the graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves' data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curve data points. The SDT agrees and has modified the curves to better clarify what is intended. The SDT added break-points and combined the curves (Attachment 1 and 2 into one curve now in Attachment 1). The curves are solely for checking the frequency trajectories of simulations and not for setting UFLS relays.

- Several commenters expressed concern that the Applicability section of the standard, as proposed, excludes generators; however, R4 requires PCs to model generator specific information. The suggestion to include the Generator Owners in the proposed standard will be problematic because Generator Owner data requirements already exist in the PRC-024-1 draft and are expected to remain. The SDT has clarified in the effective date of PRC-006 that the sub-parts related to modeling of generator trip settings will not be effective until PRC-024 is approved and effective. Adding a Generator Owner data requirement to PRC-006 would be redundant and cause double jeopardy concerns. It is the case that some standards are dependent on data requirements found in other standards. An example is that data necessary to comply with TPL standards is required under MOD standards.

- Many entities located in the Western Interconnection expressed concern that there is still a fundamental problem with the standard in that it does not specifically require the Planning Coordinators (PC) within an Interconnection to coordinate their plans amongst themselves. The SDT has worked with WECC to develop a proposed Variance to the continent-wide standard applicable to the Western Interconnection entities that addresses these concerns.

- The SDT made minor conforming changes to EOP-003-2 as requested by some commenters to clarify that the standard excludes automatic under-frequency load shedding.

Several commenters pointed out that the terminology of "other affected Planning Coordinators" (R5 & R13) is unqualified and vague. The Planning Coordinator qualification should be completely clear and unambiguous and proposed changing the applicable text in R5 from "other affected Planning Coordinators" to "other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island". (Similar language was adopted for R13.) The SDT agrees with the commenters and modified Requirements R5 and R13 by clarifying that the other Planning Coordinators are those: "whose areas or portions of whose areas are also part of the same identified island".

- Many commenters opposed the addition of Requirement R14 requiring the Planning Coordinators to respond to written comments on their program, design and data submittal. The comments indicated that this requirement either does not go far enough to secure involvement of the DPs and TOs or is procedural in nature and should not be included in a reliability standard. The SDT added this requirement between the initial and the second ballot to address concerns expressed that the DPs and TOs should have a voice in the development of the program and

implementation schedule. The SDT agrees that the DPs and TOs should have a voice in the process but in general, Planning Coordinators should be coordinating with entities in their area in fulfilling their Functional Model roles. The SDT thinks that a response to comments is about as much as a standard can require. Requirements for entities to be involved with each other and work together causes one entity's compliance to be dependent on another's. This has generally been viewed as unacceptable by the industry. This standard does not preclude development of regional standards in order to provide opportunity for all interested entities in the region to be involved.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	(1) PRC-006, R1 should be modified such that PC is required to coordinate development of the islanding criteria in consultation with TP and DP. Further, presently the RE is involved in performing or coordinating the islanding/UFLS studies. We believe that RE should continue to be involved. (2)The SDT has added R14 for PC to respond to written comments on their program, design and data submittal. Responding is not the same as involving and working with the TP and DP initially in development of the progarm, design, and data needs. We believe that PC should consult and coordinate appropriate TP and DP in development of these items. (3)EOP-003-1, R2, the last phrase should be modified from "...load shedding scheme is required." to "...load shedding scheme is necessary to minimize the risk of uncontrolled failure of the interconnected system to match the "Purpose" of the standard.
Response: (1) In general, Planning Coordinators should be coordinating with entities in their area in fulfilling their Functional Model roles. A peer review could be established for the R1 island identification criteria similar to R14, but the SDT is reluctant to add another requirement without wider industry comment. Requirements cannot be made enforceable to entities such as the RE that are not users, owners or operators of the BES under the Compliance Monitoring and Enforcement Program. (2) A response to comments is about as much as a standard can require. Requirement for entities to be involved with each other and work together causes one entity's compliance to be dependent on another's. This has generally been viewed as unacceptable by the industry. This standard does not preclude development of regional standards in order to provide opportunity for all interested entities in the region to be involved. (3) The scope of this drafting team's EOP-003 SAR is limited to removing automatic UFLS from EOP-003-1. This does not include making any			

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
changes to R2.				
Henry Delk, Jr.	SCE&G	1	Negative	1) SCE&G proposes an effective date of 24 months after regulatory approval. We believe the currently proposed effective date of 12 months after regulatory approval would not allow enough time to ensure compliance due to the requirements to establish criteria to identify islands, coordinate results with other Planning Coordinators, and reach concurrence with all other affected Planning Coordinators on UFLS design assessment results before design assessment completion. A number of these requirements cannot be met until a prior requirement is completed and each of these requirements requires coordination with other utilities which will increase the amount of time necessary to obtain compliance. As a result, SCE&G believes an effective date of 24 months after regulatory approval would be much more practical and desirable than the currently proposed 12 month effective date. 2) The graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curves data points.
Matt H Bullard	South Carolina Electric & Gas Co.	6	Negative	
Response: 1. The standard drafting team received feedback that many of the existing UFLS programs meet the performance characteristics in the proposed standard. Once this standard is approved the entities with existing programs would need a year to validate their program and validate the schedule for implementation with the UFLS entities. 2. The SDT agrees and has modified the curves to better clarify what is intended.				
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	1. Assigning the program design to the Planning Coordinator - in all honesty, this should be assigned to the Region. However, with the demise of the RRO, the RA not being available to us to assign things to, and FERC saying that we cannot assign things to the same entity that audits us (i.e., the RE), we had no real choice but to drop down one level to the PCs. 2. No LSE Applicability - this is inconsistent with FRCC's PRC-006 which assigns the amount of load to be shed to the LSE. However, the rest of the country is adamantly against assigning it to LSEs (especially in RTOs where some LSEs do not own distribution equipment at all). Hence, the DP is the preferred applicable entity to have the relays themselves. TOs are there to address historical arrangements primarily in the Midwest and West where TOs provide UFLS for DPs through grandfathered, often

Voter	Entity	Segment	Vote	Comment
				verbal, arrangements. We will still be able to aggregate smaller entities load into an FMPA-wide value for full-requirements members of FMPA through joint registration as a DP (e.g., FMPA would register as a DP to meet some of the requirements of the new PRC-006 with an associated revision to our Compliance Contract) 3. Note that there are significantly more modeling efforts than we may have done in the past; however, other regions' experience is that the increased modeling is important. 4. R10 is a little confusing, but has to do with the need to switch transmission level capacitors out of service during a UFLS event to prevent over-voltages. 5. In general, the standard is almost impossible to meet without a regional effort (e.g., 2.3). The Drafting Team struggled with this because the region is the "right" place to assignt eh program, but, we could not assign it there, so, the standard was written to sort of "force" regional cooperative efforts. In general, it should not be all that difficult to meet the requirements of the standard through FRCC efforts.
Response: 1. Thank you for understanding the difficulties with applicability. 2. Thank you for understanding the SDT position on LSE applicability. 3. The SDT agrees that modeling is a significant factor with this standard. 4. Thank you for understanding the need for R10. 5. The SDT does not think it would be impossible to comply without a regional effort, but a regional effort is certainly desirable. Thank you for understanding the SDT's approach to try to preserve the regional efforts.				
Dan R. Schoenecker	Midwest Reliability Organization	10	Negative	1. No VRFs should be "High" for a program of last resort. 2. Don't agree with R14 & R13. R13, wording "coordinate" not easy to prove for compliance. Coordinate doesn't have a valid compliance methodology since entities could be found non-compliant for actions or inaction beyond their control. The NSRS proposes wording "shall provide". 3. In R3 & R5 the wording "affected" needs better definition, the NSRS suggests rewording the affected paragraph to provide a more "bright line" criteria such that they reference PCs that share a common island to be the affected PCs. 4. R14 is procedural and not appropriate for a reliability standard. 5. Several issues need to be addressed in previously submitted comments. 6. This standard is too complicated. It could be simplified to the following requirements; it should require a documented Planning Coordinator (PC) UFLS plan, data is provided to the PC, PC should determine design

Voter	Entity	Segment	Vote	Comment
				characteristics, and verify through simulation that the plan works as designed. 7. For R2.3 & R4, each PC can't study an entire Region or Interconnection; they don't have the resources and data. Resulting studies maybe duplicative and contain conflicts in assumptions and results. 8. For R11, should not be for just any UFLS events (e.g., small local area events with few or no generators in the island), but should include all disturbance events as defined in EOP-004 that should be studied.
Response: 1. The SDT disagrees because of the importance of a last line of defense. The drafting team has posted its justification for assignment of VRFs – the justification identifies how the High VRF meets both NERC and FERC guidelines for setting VRFs. 2. "Coordination" is defined by the sub-parts of R13 (which has since been modified for further clarification). 3. The standard has been modified to address this concern. The word, "affected" is not used in the revised standard. The text in R5 was changed from "other affected Planning Coordinators" to "other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island". (Similar language was adopted for R13.) 4. Peer review procedures such as R14 are used elsewhere in approved NERC standards, specifically FAC-010 and FAC-011. The procedure has industry support. It allows Transmission Owners and Distribution Providers to at least have some say in what they will be obligated to implement. 5. Please see responses to those comments. 6. The SDT disagrees that this standard is too complicated. The requirements are necessary for reliability of UFLS programs. The commenter's suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, there would be no coordination required between adjacent Planning Coordinators, no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays. 7. The SDT agrees that each PC studying the region or interconnection is undesirable, but cannot require that they work together without setting up a condition where one entity's compliance is subject to what other entities do. If a Planning Coordinator does not wish to study the region on its own, that Planning Coordinator can try to work with the other Planning Coordinators. R7 requires sharing of UFLS data between Planning Coordinators. It is true that studies may be duplicative, but that could be avoided by Planning Coordinators working together. Conflicts should be resolved after fulfilling R5 and R13 though that is not required here. 8. The scope of the commenter's suggestion goes beyond what is necessary for UFLS purposes.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	1. Several issues still need to be addressed in previously submitted comments. 2. This standard is too complicated and should be simplified to the following requirements; a documented Planning Coordinator (PC) UFLS

Voter	Entity	Segment	Vote	Comment
				plan, data provided to the PC, the PC should determine minimum design characteristics, entities should verify through simulation that the plan works as designed, and entities should provide their plan to adjacent interconnected NERC registered entities as evidence of coordination. 3. The performance curves the attachments should clearly state what approximately expected loss of life is being imposed on generator owners / operators to meet the curve expectations. Is the Generator under frequency trip model curve expecting a 5% or 10% loss of life probability per under frequency event for each unit? Generator Owners / Operators need to understand what kind of risk a standard imposes to make decisions on how best to comply with NERC standards, even if that decision is simply whether to change unit settings to meet a proposed curve or not. Past comments. Instead of reaching concurrence, entities should be just required to inform neighbors of the assessment results. Otherwise entities could potentially be held responsible for inaction of another planning coordinator. The language could be changed to be consistent with the language in EOP-003 R3, such as, "Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected (entities)". MidAmerican notes that past under frequency event analyses are complex and that the minimum time frames for analysis and implementation should be increased to at least 2 years and exception requests for additional time should be allowed.
Response: 1. Please see responses to previous comments. Requirements to reach concurrence have been removed. The SDT does not believe that UFLS events in general will take more than a year to analyze. The SDT agrees that requests for extensions should be permitted, but requiring that of NERC cannot be written into a standard. Wide-spread and complicated events will probably end up being analyzed by NERC anyway. 2. The SDT disagrees that this standard is too complicated. The requirements are necessary for reliability of UFLS programs. The commenter's suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, coordination between adjacent Planning Coordinators cannot be achieved by simply exchanging information, there would be no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays. 3. This is a subject for Project 2007-09 and the PRC-024-1 SDT. This standard is not applicable to Generator Owners. Loss of life depends on both the specifics of events and the specific characteristics of individual generators; the question is not one that can be answered with any certainty.				

Voter	Entity	Segment	Vote	Comment
Jason Shaver	American Transmission Company, LLC	1	Negative	Although Draft 4 of Project 2007 addressed some of our issues that we identified with Draft 3, there are still the following outstanding concerns. Comments on Draft 3 of PRC-006-1: 1. The NERC Compliance Registry Criteria (Revision 5.0, Sections II.b and III.b.2) clearly states that any Transmission Owner with end-use load connected to their facilities must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. Change Applicability items 4.2 and 4.3 to simply "Transmission Owners" and "Distribution Providers", respectively without future qualification. Change the accountable entity in Requirements R8 and R9 from "UFLS entity" to "Distribution Provider". 2. Requirements (R3, R4, R9, & R10) associated with UFLS programs (which are non-primary system preservation measures) should have a lower risk factor that primary preservation measures. Reduce the "High" VRF levels to at least "Medium". 3. If a Planning Coordinator's area includes only a small portion of a Regional Entity area or an Interconnection area, then it should not have to identify the entire Regional Entity area or the entire Interconnection area as a basis for its UFLS program design (R2.3) and conduct a UFLS design assessment for those islands (R4). Remove Requirement R2.3. 4. The underfrequency design performance curve (R3.1, Attachment 1) may be appropriate for 25% UFLS programs and has an arbitrary cutoff at 60 seconds. This performance curve is not appropriate for 30%, 40%, or 50% UFLS programs, such as those that are presently in the MRO and may be fitting for the MRO or other Regions in the future. Add curves that are appropriate for at least 30%, 40%, and 50% UFLS programs to Attachment 1 or note that the curve only applies to Planning Coordinators that have UFLS programs that are not beyond 25%. 5. The overfrequency design performance curve (R3.2, Attachment 2) may be appropriate for 25% UFLS programs and has an arbitrary cutoff at 60 seconds. This performance curve is not appropriate for 30%, 40%, or 50% UFLS programs, such as those that are presently in the MRO and may be fitting for the MRO or other Regions in the future. Add curves that are appropriate for at least 30%, 40%, and 50% UFLS programs to Attachment 2 or note that the curve only applies to Planning Coordinators that have UFLS programs that are not beyond 25%. 6. The terminology of "other affected Planning Coordinators" (R5 & R13) is

Voter	Entity	Segment	Vote	Comment
				unqualified and vague, which will lead to entity and regulator interpretation problems. The Planning Coordinator qualification should be completely clear and unambiguous. Change the applicable text from "other affected Planning Coordinators" to "other Planning Coordinators in the same island". 7. The scope of Requirement R10 should not be restricted to only Transmission Owners. Distribution Providers might be able to provide automatic switching of reactive power elements that are more effective and appropriate than Transmission Owner elements. Replace "Transmission Owner" with "UFLS entity. 8. Compliance with requirements that use the term, "coordinate", are subject to wide interpretation and problematic to document. In R13, change the wording from "coordinate with other affected Planning Coordinators on the event assessment" to "provide its event assessment to other Planning Coordinators in the subject island". 9. The new R13.1 requirement (conduct a UFLS event assessment) is duplicative of R11 (conduct an assessment of a BES islanding event) [double jeopardy]. Remove Requirement R13.1. 10. A requirement (R13.2) that calls for the identification and reporting of differences between the UFLS event assessments of Planning Coordinators that evaluate the same event is inappropriate for a Reliability Standard. Other Planning Coordinators, Regional Entities, and the ERO can review the various event assessment reports and draw their own conclusions, if the assessments are provided to them. Remove R13.2 and include wording in R13, "provide its event assessment to other Planning Coordinators and Regional Entities in the subject island, as well as the ERO." 11. A requirement (R14) that calls for written responses to comments from UFLS entities regarding proposed UFLS program changes is inappropriate for a Reliability Standard. If a UFLS entity asks for an explanation from its Planning coordinator of the reasons for proposed UFLS program changes and is ignored, then they can take their grievance to the applicable Regional Entity, the ERO, or the courts. They do not need a Reliability Standard requirement to resolve the issue. Remove Requirement R14. Comments for EOP-003-1: 1. The revised wording for Requirements R3 and R5 unintentionally excludes manual underfrequency load shedding. Change the related text from "excluding under-frequency load shedding" to "excluding automatic under-frequency load shedding".

Voter	Entity	Segment	Vote	Comment
Response: 1. In some regions, Transmission Owners that do not have end-use load connected to them are the implementers of UFLS; the standard needs to accommodate that practice. 2. UFLS can be a last line of defense against catastrophic events; the SDT believes these VRFs are appropriate to that role. The drafting team has posted its justification for assignment of VRFs – the justification identifies how the High VRF meets both NERC and FERC guidelines for setting VRFs. 3. The SDT believes it desirable to preserve regional coordination of UFLS and R2.3 exists to help further that goal. Planning Coordinators could and should work together to avoid duplication, though that cannot be required. If this sub-requirement were to be removed, there would be no explicit mechanism for regional coordination of UFLS. 4&5. The attachment to R3 applies to load-generation imbalances of up to 25 percent. While it may be more difficult for programs with a higher percent capability to satisfy these criteria, the SDT believes this is achievable. Coordination with generator tripping is still necessary and the same generator curves (coordinated with PRC-024-1) would apply unless a regional variance is proposed. 6. The standard has been modified to address this concern. The word, "affected" is not used in the revised standard. The text in R5 was changed from "other affected Planning Coordinators" to "other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island". (Similar language was adopted for R13.) 7. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Owner; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding by the Transmission Owner (only). The switching of elements is generally performing at higher voltages than distribution voltages and as a result decided to not include the Distribution Providers in Requirement R10.8. Exchange of event assessments between Planning Coordinators is implied. The sub-parts of R13 in the revised standard specify what is meant by "coordinate." 9. The previous R13.1 has been removed to address this point (also R5.1). 10. The SDT disagrees; a first step in resolving differences is to identify those differences. The desire is for differences to be resolved somehow before compliance audits, though resolution cannot be required. An alternative is for Planning Coordinators to work together on one event assessment, though that cannot be required either. 11. The SDT believes R14 is appropriate to give Transmission Owners and Distribution Providers opportunity to comment BEFORE a UFLS program is finalized and they become subject to compliance to provide the specified load tripping. The term "automatic" has been added to EOP-003 R3 and R5 per the commenter's suggestion.				
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	Although the latest revision is improved over the previous one, especially in terms of added clarity in some areas, there is still a fundamental problem in that it does not specifically require the Planning Coordinators (PC) within an Interconnection to coordinate their plans amongst themselves. The current version of the standard would allow for all of the PCs within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are PCs. The standard still

Voter	Entity	Segment	Vote	Comment
				references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. PG&E believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection. The draft standard is also very prescriptive is some cases, going as far as specifying maximum Volts per Hertz limits in simulated studies of islanded scenarios, as well as frequency versus time envelopes or boundaries that specify acceptable over/under frequency excursions. These types of performance limits should be specified at the Interconnection level based on the characteristics of the Interconnection, not at the Continent-wide level.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Thomas R. Glock	Arizona Public Service Co.	3	Negative	Although the SDT has made changes in trying to define the Protection System the definition remains too prescriptive. In particular, the devices providing current and voltage inputs as well as the dc supply. These items are also used for other functions not related to the reliability of the BES. They are critical to business and operation of the generating systems and not solely dedicated to protective relaying. Including them in the definition obligates the utility to methods where there should be some discretion.
Response: This comment does not seem to relate to this standard, PRC-006.				

Voter	Entity	Segment	Vote	Comment
Linda R. Jacobson	City of Farmington	3	Negative	Another concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The curves are solely for checking the frequency trajectories of simulations and not for setting UFLS relays. The Quebec interconnection has a variance. Since the standard was last balloted, WECC has proposed an Interconnection-wide variance to the requirements in this standard, but the variance does not propose different curves. The Planning Coordinators do have the responsibility to determine UFLS design parameters including frequency set points. The SDT decided in the first draft that these parameters should not be determined in a continent-wide standard for the very reason that regions and interconnections have unique characteristics. This is decidedly not a least common denominator approach. The SDT disagrees that the performance characteristic curve approach is reverse engineering, but rather designing to a target. The reliability justification for the curves is their coordination with generator tripping.				
Gregory Campoli	New York Independent System Operator	2	Negative	Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved. This standard seems to be contrary to FERC's stated concern (Oct. 2009 Washington DC meeting) to develop a standard that can support the program it was designed to enforce.....the applicability as stated in the standard and by NERC registry criteria restricts and excludes the need for GO's that may in aggregate be necessary for a reliable UFLS program, to adhere to the standard. The standard also is potentially in conflict with the work being done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. Sufficient coordination on NERC Standards development needs to occur on a going forward basis.
Response: The suggestion to include the Generator Owners in the proposed standard will be problematic because Generator Owner data requirement already exist in the PRC-024-1 draft and are expected to remain. The SDT has clarified in the effective date of PRC-006 that the sub-parts related to modeling of generator trip settings will not be effective until PRC-024 is approved and effective. Adding a Generator Owner				

Voter	Entity	Segment	Vote	Comment
data requirement to PRC-006 would be redundant and cause double jeopardy concerns. It is the case that some standards are dependent on data requirements found in other standards. An example is that data necessary to comply with TPL standards is required under MOD standards.				
Claudiu Cadar	GDS Associates, Inc.	1	Negative	Applicability. 4.2. The wording in the standard may need to reformulate to read "[...] established by the Planning Coordinators within the Regional Entity's footprint.[...]". Applicability. 4.3. While SDT response indicates that 4.3 is intended for TOs that may need to switch equipment other than load, however we consider that 4.3 is a redundant assignment since reference to TOs controlling UFLS equipment already included in 4.2.2. Effective Date. 5. Depending on when this standard becomes mandatory and enforceable, it may fall between entities' budgeting periods. An 18 months implementation would allow for all entities to budget the funds necessary to implement the standard. Requirements. R1. While the SDT response to one of RBB member states that R1 and R2 are meant to only "devise some criteria considering historical events and system studies and use those criteria to identify some islands" understanding that "this not mean that every conceivable island must be identified", we consider that both R1 and R2 requirements should be reworded to reflect this intended approach. While the SDT has added requirement R14 with regards to the collection and response to comments on the UFLS program, schedule for implementation and collection of data, there is no requirement to state how the PC will address comments (if any) from the participating entities on the suggested criteria. We find appropriate to include an interpretation to standard requirements. We also noted that the SDT proposed a "Medium" VRF and we consider that since the requirement is not meant to draw specific lines, the VRF should be set back to "Lower" as originally proposed. Requirements. R8. How the UFLS entity suppose to provide data to the Planning Coordinator and when is suppose to do that? The newly added requirement R14 regarding the collection and response to comments on the UFLS program, schedule for implementation and collection of data does not establishes the time limits and how the UFLS entity is to provide data to the PC. This requirement leaves all these at the PC discretion without any specific timelines, or process sequencing which both the PC and the UFLS entity should follow.

Voter	Entity	Segment	Vote	Comment
				Requirements. R9, R10. What if the UFLS entity does not agree with Planning Coordinator's assessment? See comment on R8; requirement R14 does not respond to this question.
Response: The phrase "…within the Regional Entities footprint" is unnecessary since it is the Planning Coordinator's footprint that rules UFLS implementation. Applicability 4.3 is specifically for Transmission Owners that may need to switch Elements other than load or UFLS equipment, and in fact may not even have load connected to their facilities or UFLS equipment. R1 and R2 are in fact worded to reflect the SDT's intended approach. The schedule for implementation by UFLS entities is determined by the Planning Coordinators, not the Implementation Plan or the standard. Planning Coordinators will need to address any R14 comments before finalizing their UFLS program and schedule, which puts a time limit on their responses in view of the timeline imposed by the Implementation Plan. R14 VRF is already "Low." (Now changed to "Lower.") The schedule and format for UFLS Entities to supply data to the Planning Coordinator is based on the schedule and format devised by the Planning Coordinator, subject to their response to R14 comments. That is all the standard can require. A standard cannot require entities to agree with each other.				
Clement Ma	BC Hydro and Power Authority	5	Negative	BCHPA concurs with WECC comments as follows: The primary concern identified in the first position paper is that the proposal does not require coordination within individual interconnections. The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. WECC believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be necessary to meet the continent-wide

Voter	Entity	Segment	Vote	Comment
				performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	Comments associated with the negative vote are contained in the Project 2007-01 comment form submitted by TVA
Response: Please see SDT responses in that comment form.				
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	comments provided on comment form
Response: Please see SDT responses in that comment form.				
Robert W. Roddy	Dairyland Power Coop.	1	Negative	concerned that generation limits are too conservative.
Response: Not sure if this comment means too conservative from a generator's perspective or from the transmission reliability perspective. The SDT believes, in coordination with the 2007-09 project team, that an acceptable balance has been achieved between competing interests.				
Edward F. Groce	Avista Corp.	5	Negative	Coordination of UFLS plans should be required in the standard.
Response: Coordination of UFLS plans is achieved by (1) common performance criteria in R3, (2) coordination between Planning Coordinators within a region or interconnection per R2.3 and R5, and (3) coordination per R5 within any other identified islands that span multiple Planning Coordinator areas.				
Paul Morland	Colorado Springs Utilities	1	Negative	CSU offers the following comments: R3 (Attachments) It is not clear how attachment 1 should be used. Are the curves performance curves? Set point curves? R10 Need more clarity on what is meant by "Automatic Switching of Elements"? Does it mean a TO needs to automatically switch capacitor banks to avoid overvoltages?
Response: Attachment 1 curves are performance criteria consisting of boundaries for frequency trajectories in simulations run to assess UFLS performance. The SDT added break-points and combined the curves (Attachment 1 and 2 into one curve now in Attachment 1). The curves are solely for checking the frequency trajectories of simulations and not for setting UFLS relays. Yes, "automatic switching of Elements" refers to switching of, among other Elements, cap banks. R10 has been modified to remove the confusion.				

Voter	Entity	Segment	Vote	Comment
Michael F Gildea	Dominion Resources Services	3	Negative	Currently there is no requirement for Generator Owners to provide trip settings for non-conforming units to the Planning Coordinator. Absent such a requirement, the responsibility for compliance would be placed on the Transmission Owner. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. So, we suggest the addition of a requirement (applicable to the Generator Owner) to provide the information (as needed in R3-R3.3.3) to the Planning Coordinator. Approving this standard without addressing these comments will not achieve the reliability objective of the FERC Order 693 directive and ultimately will result in a standard that cannot be implemented as written.
Mike Garton	Dominion Resources, Inc.	5	Negative	
Response: PRC-006 and PRC-024 are coordinated and the generator curves and tables match. The SDT recognizes that PRC-024 may be approved at a different time and has inserted a provision in the implementation plan document to account for that possibility. Generator applicability is deferred to PRC-024 to avoid double jeopardy. The number of non-conforming generators is expected to be small and should not cause a compliance issue for Planning Coordinators in an interim period, if any, before Generator Owner data becomes available to them.				
Stanley M Jaskot	Entergy Corporation	5	Negative	Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. In M3 it is unclear what action is intended by the phrase “including the criteria itself”. Since the criteria is specified in R3, it is recommended that the phrase be deleted. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: “Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators.” We also recommend that the wording in R5 be changed to: “Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by that Planning Coordinator which include a portion of its footprint along

Voter	Entity	Segment	Vote	Comment
				with portions of another PC(s) footprint." The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. We also recommend that the High and Severe VSLs that contain the phrase "shall conduct and document" to read "conducted and documented". The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information.

Voter	Entity	Segment	Vote	Comment
				The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the 500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events.

Response: The SDT agrees and has modified M3 to remove the phrase "including the criteria itself".

The SDT has modified R5 and M5 to reflect the intent that only UFLS programs within the PC areas that are a part of the island under study need to work in conjunction to meet the performance requirement in R3.

The SDT also modified R5 and M5 to remove the "concurrence" requirement and provide a means by which each PC can meet this requirement alone or by working with other PCs.

The SDT has modified the VSLs for R11 to make these corrections.

R4 – consideration of timeliness - The SDT considered this and decided that the program reassessment is a binary task which automatically makes this a severe violation if not completed within the 5 year timeframe.

The SDT has modified R13 to eliminate any duplication between R13 and R11.

R14 requires the UFLS entities be notified of a comment period and for the PCs to respond to those comments prior to a UFLS program becoming effective. Requirement R3 has been modified to specifically indicate that the UFLS program must include "**notification** of and a schedule for implementation" in support of your suggestion.

The SDT modified the implementation plan to state, "Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1." Per the implementation plan, the requirement to model data from the GOs is not mandatory until after the GOs are required to provide the data by PRC-024. This is similar to the requirement to model the BES by the TPL standards, while the requirement by entities to provide the data used to model the BES is contained in the MOD standards.

The existing standard PRC-009, which this standard is intended to replace, currently requires that an assessment be performed for all events regardless of size. The SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the requirement the same or better than what exists today.

Voter	Entity	Segment	Vote	Comment
Daniel Brotzman	Commonwealth Edison Co.	1	Negative	EOP-003-1 needs to define the criteria as to when and how UVLS schemes are installed to provide consistency direction to Planning Coordinators and the entities that have to install UVLS schemes. The relationship between the use of UVLS and compliance with TPL-001 standards should be clarified. Is load shedding (including UVLS) allowed to meet the performance criteria in TPL-001? The standard should define when UVLS are applicable to the BES and thus subject to the requirements of EOP-003. UVLS schemes developed for distribution or other purposes beyond criteria should not be discouraged through regulatory burden. UVLS should be carefully defined. Many types of load will cut out on low voltage. PRC-006-01: The standard lacks guidance as to what the trip settings should be. It is not clear as to how Attachment 1 should be used and doesn't provide specific detail for under frequency set points. Exelon disagrees that R3.3 is easier to understand. Clarification is needed as to where the underfrequency set points are. Do all entities contribute equally to Attachment 1? There needs to be a standardized relationship between GO and TO/DP participation in obtaining the desired level of system performance. There should also be explicit criteria as to what the expectations are for each individual entity. It should be clear that all UFLS entities are to participate equally and that larger entities will not be expected to carry the burden for smaller entities. There should be some recognition in the standard that UFLS schemes currently exist and effort should be made to avoid needlessly changing relays or settings on many thousands of installations if some arbitrary and common set points were to be determined by the PC, thus causing needless expense. It is likely desirable to have slightly different settings for UFLS across a footprint so as to not create load changes that are too abrupt. The current practice of allowing contractual agreements between GOs and DPs for additional load shedding as a voluntary business decision, in the event that a unit owner doesn't comply with the unit trip settings should be addressed. Exelon does not agree with the concept of allowing neighboring Planning Coordinators to define or modify islanding criteria. There should be a single criteria for the determination of an island which is consistent across

Voter	Entity	Segment	Vote	Comment
				the interconnection, unless a specific geographic or regional exception is identified. Even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint.
Response: Another drafting team is being assigned EOP-003. The scope of the UFLS drafting team is restricted by the SAR to removing automatic UFLS from EOP-003 only. The under and over frequency performance curves in Attachment 1 are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misconstrued as applying to UFLS relay set points. Many of the issues the commenter raises are going to need to be dealt with by the Planning Coordinators. It would be very difficult and probably not in the interest of BES reliability for these issues to be resolved in this standard. R3.3 is based on IEEE guidelines for setting V/Hz protection. The Planning Coordinator, as part of the UFLS program design, will need to determine the participation level of the variously sized Transmission Owners and Distribution Providers. The SDT fully expects that existing UFLS programs will be sufficient to comply with the performance characteristic curves and Planning Coordinators will not need to arbitrarily re-determine UFLS design parameters. The SDT has addressed the matter of GO versus TO/DP obligation for non-conforming generators and has decided that, for the likely small amount of non-conforming generation, that it should be a small burden, if any, to be spread across multiple TOs and DPs. Neighboring Planning Coordinators cannot redefine or modify another Planning Coordinator's R1 island determination criteria. A Planning Coordinator may, however, select an island that overlaps a neighboring Planning Coordinator's footprint in complying with R2. A single criterion for island determination is not something that can be put into a continent-wide standard because there are likely to be many acceptable approaches to these criteria.				
Robert Martinko	FirstEnergy Energy Delivery	1	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote. We feel that the new R14 puts an administrative compliance burden on the PC because it requires a response to all written comments. Furthermore, R14 does not address subsequent changes to the UFLS program and more importantly fails to address FE's underlying concern that the standard still gives full authority to the PC to set an implementation schedule for a UFLS Entity.
Kenneth Dresner	FirstEnergy Solutions	5	Negative	
Mark S Travaglianti	FirstEnergy Solutions	6	Negative	

Voter	Entity	Segment	Vote	Comment
Douglas Hohlbaugh	Ohio Edison Company	4	Negative	We believe that PRC-006-1 should specifically allow the UFLS entity at least 12 months to comply with the PC's UFLS program upon being notified of new obligations. Please see our suggested revision to R14 at the end of these ballot comments. In Requirement R3 it is implied that the PC will notify and coordinate with the UFLS entity per the phrase "including a schedule for implementation by UFLS entities within its footprint", and in Requirement R14 it is also implied. However, there should be an explicit requirement in this standard (either in R3 or R14) for the PC to notify the UFLS entity of their obligations per the PC's UFLS program. As a minor note, in the initial ballot we stated that we noticed that EOP-003-1 is the current version approved by FERC. The revised version per this project should therefore be EOP-003-2. Based on the concerns we have stated above, we suggest a revision to R14 as follows: "R14. Each Planning Coordinator shall meet the following during the development of the UFLS program and during subsequent revisions of the program that require additional UFLS equipment installations by the UFLS entity [VRF: Low][Time Horizon: Long-Term Planning]: 14.1. Submit an initial draft of its UFLS program for review and feedback by the identified UFLS Entity before the UFLS program is finalized. 14.2. Assure that the schedule for implementation affords the UFLS entity at least 12 months to achieve compliance."
Response: R14 establishes a peer review process, but cannot go further due to the need to have clear assignments of responsibility. A regional standard could be drafted to gain the participation of other entities. The SDT does not believe that a written response to comments is burdensome. EOP-003-1 should be EOP-003-2 and this has been fixed. The SDT believes that the implied requirements for Planning Coordinators to notify UFLS Entities are sufficient, and that Planning Coordinators, in fulfilling their role as coordinators, will not impose unreasonable demands on UFLS Entities. Requirement R3 has been modified to specifically indicate that the UFLS program must include "**notification** of and a schedule for implementation" in support of your suggestion.				
Kevin Querry	FirstEnergy Solutions	3	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote for the standard as written. Although we agree that the Planning Coordinator is the appropriate functional entity to develop and implement a UFLS program, we are concerned with the fact that UFLS entities may not know the specifics of their responsibilities until long after this standard is approved. The SDT should consider adjusting the language of the standard to require more

Voter	Entity	Segment	Vote	Comment
				transparency and coordination with the UFLS entities during the PC's development of the UFLS program. Also, per the implementation plan, the PC will be given one year to develop its UFLS program. However, the timeframe for the UFLS entity is based on the schedule imposed by the PC. The implementation plan should allow the UFLS entity at least one year (maybe more per capital budget cycles) from the time the PC identifies the UFLS entity in their UFLS program. The UFLS entity will need sufficient lead time in those instances that require purchase of new UFLS equipment that will require long term budget planning for implementation. The UFLS entities are identified in the UFLS program established by the PC. However, it is not clear where the PC is explicitly required to notify and coordinate with the UFLS entity. In Requirement R3 it is implied that the PC will notify and coordinate with the UFLS entity per the phrase "including a schedule for implementation by UFLS entities within its footprint". This requirement needs to be more explicit that the PC will notify the UFLS entity, and the measure for R3 needs to require proof that the PC has done this. We are concerned about the coordination between this UFLS SDT and the GV SDT. It will be difficult to approve and begin implementing the PRC-006-1 standard while the PRC-024-1 standard is still under development and scheduled for approval and implementation at a much later date. For these requirements to be adequately coordinated, the two standards need to be developed, balloted and implemented at the same time. Alternatively, consider adding the following statement in the PRC-006-1 Implementation Plan: "The Effective Date and implementation of this PRC-006-1 standard requires coordination with standard PRC-024-1. Excluding requirement R1, the Effective Date of PRC-006 shall be the later of 1) the completion of the Implementation Plan for PRC-006 or 2) the completion of the Effective Date of the PRC-024-1 standard upon completion of its Implementation Plan."
Response: R14 establishes a peer review, but cannot go further due to the need to have clear assignments of responsibility for compliance. Requiring entities to coordinate with each other or work together causes one entity's compliance to be dependent on another's. This has generally been viewed as unacceptable by the industry. A regional standard could be drafted to gain the participation of other entities in the UFLS program and implementation schedule. In general, Planning Coordinators should be coordinating with entities in their area in fulfilling their Functional Model roles. Requirement R3 and Measure M3 were both modified to include "notification" as suggested. The SDT recognizes that PRC-024 may be approved at a different time and has inserted a provision in the implementation plan document to				

Voter	Entity	Segment	Vote	Comment
account for that possibility. The number of non-conforming generators is expected to be small and should not cause a compliance issue for Planning Coordinators in an interim period, if any, before Generator Owner data becomes available to them. The aspects of coordination between PRC-006 and PRC-024 are a small subset of the content of each standard and do not warrant delaying implementation of one standard until the other is approved.				
James A Ziebarth	Y-W Electric Association, Inc.	4	Negative	From Question 3 on the comment form: Regarding the VSLs for R8, the UFLS entities cannot be punished for failing to meet a schedule if the schedule is not mutually agreed upon between the Planning Coordinator and the UFLS entities to ensure that the UFLS entities are capable of meeting such a schedule. At the very least, there must be some protection for the UFLS entities provided that requires the Planning Coordinator(s) to give the UFLS entities long-term notice of the deadlines that they will need to meet. The lack of any scheduling restrictions for the Planning Coordinators in the standard as written has a strong potential to cause enormous burdens on small UFLS entities that simply do not possess the resources to deal with such data reporting requirements without sufficient advance notice. Additionally, the UFLS entities cannot be penalized for failing to submit data in a format over which they have no control or input. The Planning Coordinator should be required to consult with the UFLS entities and decide upon a mutually agreeable data format in order to ensure that the UFLS entities are capable of providing the required data in the required format. With no language in the standard limiting or clarifying what data can be required of the UFLS entities by the Planning Coordinator, this provision at least should be made to protect small UFLS entities with highly limited resources for dealing with such data reporting requirements. From Question 8 on the comment form: Because Load Serving Entities (not Distribution Providers) are actually responsible for the load in the current Functional Model and Compliance Registry Criteria, they should also be included in the applicability section of this standard. From Question 12 on the comment form: Y-WEA is concerned about this requirement in that it seems to require the installation of facilities rather than just relays. 16 USC 824o (a)(3) gives NERC the authority to regulate existing facilities and planned additions or modifications to those facilities, not to prompt or require modifications or additions to the existing facilities. This proposed requirement seems to run afoul of this section of the USC.
Response: PCs should work with UFLS entities on schedule for data reporting. Requirement R14 is designed to facilitate communication between these entities. Ultimately, the PC is required to perform the design assessments which it cannot do without the necessary modeling data. The				

Voter	Entity	Segment	Vote	Comment
schedule and format for UFLS Entities to supply data to the Planning Coordinator is based on the schedule and format devised by the Planning Coordinator, subject to their response to R14 comments. That is all the standard can require. A standard cannot require entities to agree with each other. The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. The SDT is not sure where this concern is coming from. If the comment is referring to Requirement R10, it does not require the installation of any equipment other than relays to facilitate the "automatic switching of capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding".				
Jeff Mead	City of Grand Island	5	Negative	I echo MRO NSRS comments.
Response: Please see SDT response to MRO comments.				
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Negative	It is apparent that this UFLS Standard is very complex and wish to thank the SDT in their efforts so far. A UFLS system is in place as a last line of defense in arresting frequency when operator actions cannot keep up with a rapid decline in frequency. There are many other step that are to be taken prior to automatic UFLS action. With that being said, there are several areas that still need to be reviewed. The word "coordinate" (R13) should be replaced with "shall provide" since proving compliance within different regions will be met with different views. The "High" VRFs make this another priority. As stated in the FERC Technical Conference on July 6, 2010, everything cannot be a priority. Do not see how R14 supports the reliability of the BES, it is purely procedural. Do not think that a PC has the capability to do a design assessment (R4) based on R2.3 for "or the Interconnection in which the PC's area resides. Since there are many (special) attributes that apply to different PC areas, this Standard could be boiled down to 1) Require a documented PC UFLS plan, 2) Data prescribed by the PC shall be forwarded to the PC from entities within their area that own or operate UFLS devices, 3) PC's should determine design characteristics based on the area's physical capabilities and limitations, 4) Verify through simulation that the plan works as designed, 5) PC's shall provide their plans to other physically connected PC areas. This would allow each PC with determining system characteristics unique to their system.

Voter	Entity	Segment	Vote	Comment
Response: In R13, the sub-parts define what is meant by "coordinate." The sub-parts are specific enough that there should not be a problem with differing interpretations. UFLS can be a last line of defense against catastrophic events; the SDT believes these VRFs are appropriate to that role. The drafting team has posted its justification for assignment of VRFs – the justification identifies how the High VRF meets both NERC and FERC guidelines for setting VRFs. Peer review procedures such as R14 are used elsewhere in approved NERC standards, specifically FAC-010 and FAC-011. The procedure has industry support. It allows Transmission Owners and Distribution Providers to at least have some say in what they will be obligated to implement. In R2.3, the island can be either the region or interconnection; it does not have to be the interconnection. The commenter's suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, coordination between adjacent Planning Coordinators cannot be achieved by simply exchanging information, there would be no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays.				
Hugh A. Owen	Public Utility District No. 1 of Chelan County	6	Negative	It is import tha6t there be single coordinated plan for the WECC. It appears this proposed standard as worded, would allow for the possibility of as many different UFLS plans within an interconnec as there are planning coordinators without a mandate that they be coordinated.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	It is unclear from the Standard that not forming islands in UFLS design is acceptable. Recommend the SDT consider including language to clarify that is not mandatory that system islands by formed in every UFLS design configuration.
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Scott Heidtbrink	Kansas City Power & Light Co.	5	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Response: A Planning Coordinator must identify at least one island to be used as the basis for the R4 UFLS design assessment. However, this does not mean that islands must be identified from a Planning Coordinator's R1 criteria. As a minimum, the region or interconnection in which a Planning Coordinator's area is located must be identified as an island per R2.3.				

Voter	Entity	Segment	Vote	Comment
Louise McCarren	Western Electricity Coordinating Council	10	Negative	Main concern is that this proposal still doesn't require an interconection-wide coordinated plan. While the current version of the standard would allow for all of the Planning Coordinators within an interconnection to agree upon and implement a single coordinated plan, it does not require a single coordinated plan. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. WECC believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Terri F Benoit	Entergy Services, Inc.	6	Negative	NEGATIVE BALLOT WITH REASONS Entergy Ballot PROJECT 2007-01 UNDERFREQUENCY LOAD SHEDDING PROGRAM REQUIREMENTS Ballot Ending July 16, 2010 The following are the reasons associated with our Negative Ballot. Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. In M3 it is unclear what action is intended by the phrase “including the criteria itself”. Since the criteria is specified in R3, it is recommended that the phrase be deleted. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: “Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators.” We also recommend that the wording in R5 be changed to: “Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by

Voter	Entity	Segment	Vote	Comment
				that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint." The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. We also recommend that the High and Severe VSLs that contain the phrase "shall conduct and document" to read "conducted and documented". The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required

Voter	Entity	Segment	Vote	Comment
				information. The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the 500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events.

Response: The SDT agrees and has modified M3 to remove the phrase "including the criteria itself".

The SDT has modified R5 and M5 to reflect the intent that only UFLS programs within the PC areas that are a part of the island under study need to work in conjunction to meet the performance requirement in R3. The SDT also modified R5 and M5 to remove the "concurrence" requirement and provide a means by which each PC can meet this requirement alone or by working with other PCs.

The SDT has modified the VSLs for R11 to make these corrections.

The SDT considered this and decided that the program reassessment is a binary task which automatically makes this a severe violation if not completed within the 5 year timeframe.

The SDT has modified R13 to eliminate any duplication between R13 and R11.

Requirement R3 has been modified to specifically indicate that the UFLS program must include "**notification** of and a schedule for implementation" in support of your suggestion.

The SDT has added R14 which now requires the UFLS entities be notified of a comment period and for the PCs to respond to those comments prior to a UFLS program becoming effective.

The SDT modified the implementation plan to state, "Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1." Per the implementation plan, the requirement to model data from the GOs is not mandatory until after the GOs are required to provide the data by PRC-024. This is similar to the requirement to model the BES by the TPL standards, while the requirement by entities to provide the data used to model the BES is contained in the MOD standards.

The existing standard PRC-009, which this standard is intended to replace, currently requires that an assessment be performed for all events regardless of size. The SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the requirement the same or better than what exists today.

Voter	Entity	Segment	Vote	Comment
Richard Salgo	Sierra Pacific Power Co.	1	Negative	Negative vote prompted by several concerns: First, the Standards as proposed are a disturbing departure from the present practice of Regional and Interconnection-wide coordination of off-nominal frequency protection. We feel that it must be approached on an Interconnection-wide basis, not as individual Planning Coordinators. The goal should be that the Planning Coordinators develop a coordinated interconnection-wide off-nominal frequency scheme design. This is imperative to ensure adequate UFLS protection across the Interconnection. Secondly, applicability does not appear to include entities who must be responsible to ensure that the UFLS is carried out, for instance, the LSE's and DP's that necessarily must implement the prescribed UFLS protection devices at the distribution level. Finally, we disagree with the concept of frequency-vs-time curves, as this approach will fall short of addressing the unique characteristics of the various NERC Interconnections.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	oThe proposed measures are vague, not specific and not performance based which leave too much up to the Auditor's interpretation. oThe proposed standard does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. oThe primary purpose of the UFLS Plan is designed to mitigate the need to form islands by balancing loads and resources. It is a secondary function to balance the loads and resources after the islands have been formed. It appears the Drafting Team focused on the islanding event rather than assuring the interconnection integrity is maintained. Frequency is an interconnection issue not and individual island issue and therefore not driven by an individual PC but by a coordination of PCs effort within the interconnection. o The WECC UFLS-DT believes there should be recognized sub-area groups, (consisting of PCs, as assigned by the Reliability Assurer (RA)). These sub-groups would be the agent for the PCs, and would assure the overall coordination within the interconnection. For example, the WECC RA recognizes the following sub-areas for UFLS coordination within the Western Interconnection (WI): Southern Islanding Load Tripping Group,

Voter	Entity	Segment	Vote	Comment
				the Northwest Power Pool UFLS group and the WECC Off Nominal Frequency Load and Restoration Plan. Without the RA assuring coordination of the sub-groups, PCs could randomly form sub-area groups whose plans may not coordinate on an interconnection wide basis or even address the interconnection reliability needs, but coordinated among the randomly formed sub-groups. The standard, requirements, and measurements should reflect the uniqueness of the individual interconnections and not common, continent wide prescriptions.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Francis J. Halpin	Bonneville Power Administration	5	Negative	Please see BPA's comments submitted during the formal comment period ending 7/17/10.
Rebecca Berdahl	Bonneville Power Administration	3	Negative	
Response: Please see the SDTs response to your comments submitted during the formal comment period ending 7/17/10.				
Jim D. Cyrulewski	JDRJC Associates	8	Negative	PRC-006 remains overly complicated especially Requirement 14.
Response: R14 establishes a peer review. It is not overly complicated.				
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	PRC-006-1 implicitly allows incompatible UFLS programs to exist within the same synchronous interconnection. Each PC is not only allowed, but is required to design and implement its own UFLS programs. A requirement does exist in PRC-006-1 that the UFLS programs be “coordinated” among “all other affected Planning Coordinators.” Nevertheless, “coordinated” is a vague term and can simply mean “notified”. How coordination is measured

Voter	Entity	Segment	Vote	Comment
Janelle Marriott	Tri-State G & T Association Inc.	3	Negative	and enforced is also questionable. Allowing multiple UFLS schemes to exist in the same interconnection, with no oversight as to how well they interact is a haphazard approach. UFLS programs that are not developed interconnection-wide can, among other things, result in excessive load shedding and corresponding frequency oscillations that degrade into cascading outages. PRC-006-0 requires the Regional Entity to "develop, coordinate, and document a UFLS program." This top-down approach makes a more congruous interconnection-wide program more likely. Further, since PRC-007-0 requires UFLS owners to comply with the Regional Entity's programs, individual conflicting UFLS schemes among UFLS Entities are also less probable. As currently written, PRC-006-1 specifically removes both the oversight and scheme consistency the previous standards provided. This makes conflicting programs more likely. This degrades, not improves Bulk Electric System Reliability. The NERC Functional Model defines the Reliability Assurer as the entity that "...coordinates activities of functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer area and adjacent areas." With regard to UFLS, the coordination of functional entities is absolutely necessary to secure the reliability of the BES. This coordination function belongs to and is best handled by the Reliability Assurer. More specific comments on the draft standard follow, but the fundamental thesis of the current draft, which moves UFLS design responsibility down from the RA to the PC, should be changed. The responsibilities to design, coordinate, and analyze a UFLS program within an interconnection should remain with the RA. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. A. Introduction 1.-3. No comment. 4.1. should be changed from Planning Coordinators to Reliability Assurers. 4.2. Planning Coordinators should be changed to Reliability Assurers.

Voter	Entity	Segment	Vote	Comment
				4.3. is redundant to 4.2.1. and should be removed. **Response**: The SDT thinks there is confusion over having Transmission Owners as part of UFLS Entities but separated out as Transmission Owners in Requirement R10.. The team reviewed the rationale for this structure. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements. Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Owner; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding by the Transmission Owner (only). The switching of elements is generally performing at higher voltages than distribution voltages and as a result decided to not include the Distribution Providers in Requirement R10. 5. No comment. B. Requirements R1. Reliability Assurers rather than individual Planning Coordinators need to develop and document the potential for island formation. However, this requirement may not contribute to the reliability of the BES and could be removed. R2. Reliability Assurers rather than individual Planning Coordinators are the best entities to determine how islands should be formed. The current registration by numerous entities as Planning Coordinators does not lend itself to a comprehensive individual island formation methodology. R2.3. seems to require each Planning Coordinator to ultimately divide into multiple islands or separate its transmission system from all other transmission systems as its own island. The purpose of the UFLS program should be to mitigate the need to form islands by balancing total system loads and resources. It is only a secondary function to balance the loads and resources after the islands have been formed. Recommend eliminating R2 unless the Reliability Assurer becomes the functional entity responsible for the UFLS program development. **Response**: The SDT does not believe that designating islands as a secondary function of UFLS is a distinction useful for reliability because

Voter	Entity	Segment	Vote	Comment
				most UFLS operations are seen to occur following island formation. Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. R3. Underfrequency events are not local events that individual systems experience unless islands have already formed. The total interconnected system ratio of generation to load needs to be evaluated to determine at what frequencies the loads must be tripped and restored. Performance of this function by individual Planning Coordinators is a duplication of effort and will still require the entities to concur with interconnected/affected Planning Coordinators (see R5.). We recommend that the functional entity that develops the UFLS program be changed from Planning Coordinator to Reliability Assurer. R3.1. and R3.2. We recommend combining Attachment 1 and Attachment 2 into a single graph, making frequency the abscissa, and requiring simulations to maintain frequencies inside the resulting envelope. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. The SDT added break-points and combined the curves (Attachment 1 and 2 into one curve now in Attachment 1). The curves are solely for checking the frequency trajectories of simulations and not for setting UFLS relays. R3.3. Volts/Hertz (V/Hz) protection should be based upon transformer and generator protection requirements It is possible that V/Hz generator

Voter	Entity	Segment	Vote	Comment
				protection schemes exist that are more sensitive than 1.10 p.u. and 1.18 p.u.. The bases for the 1.18 p.u. and 1.1 p.u. values are not evident and may not be technically supportable when compared against actual protection settings or allowable post-contingency voltage bands. Compliance with these performance characteristics does not guarantee the generators will stay online during UF events. Recommend removing R3.3.1, R3.3.2, and R3.3.3 and replacing R3.3 with: "Generator and generator step-up transformer V/Hz protection elements shall not be violated." **Response**: The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1. The SDT recognizes that some generators may not meet those curves and wants the PC to specifically model the trip settings of those generators. We understand that V/Hz is not a standard output, but, it should not be a large effort to monitor voltage and frequency, divide the two, and integrate over each time step. The SDT believes there is a need for V/Hz requirements because shedding load will cause voltages to climb, which may cause excitation systems / voltage regulators to reach the end of their range, which can lead to a V/Hz condition that could cause generators to trip through GSU protection or other similar protection systems. Therefore, the SDT believes that V/Hz of 1.18 p.u for 2 seconds, etc., can be reached at significantly higher frequencies than 57.2 Hz. The standard does not require modeling of V/Hz protection and only requires monitoring of voltage and frequency and designing the UFLS program to meet the performance criteria described in 3.2. The V/Hz values are based on Threshold values from IEEE C37.102 (Guide for AC Generator Protection) and C37.106 (Guide for Abnormal Frequency Protection for Power Generating Plants), and C37.91 (Guide for Protective Relay Applications to Power Transformers). R4. The Reliability Assurer should be the entity that conducts and documents the periodic UFLS program periodic design assessment. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a

Voter	Entity	Segment	Vote	Comment
				set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. R5. This requirement is a good example of why the UFLS should be developed by the Reliability Assurer and not individual Planning Coordinators, since each must coordinate with all the other affected Planning Coordinators. “Coordinate” can be as simple as communication between parties (see PRC-001-1 R5) or can be detailed technical study performance and mutual agreements (see PRC-001-1 R3 and M1). If the Reliability Assurer has an approved UFLS program then the UFLS entities will need to comply with the program and the vague “coordination” issue no longer exists. R6. Change Planning Coordinator to Reliability Assurer. Entity. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. R7. Change to “Each Reliability Assurer shall provide its UFLS database containing data necessary to model its UFLS program to other Reliability Assurers within its Interconnection within 30 days of a request. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.

Voter	Entity	Segment	Vote	Comment
				R8. Replace every instance of Planning Coordinator with Reliability Assurer. Requiring UFLS entities to provide UFLS scheme data is proper; however, this requirement may duplicate R1.4 in MOD-13-1. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. R9. And R10. Since a Transmission Owner is a UFLS Entity, these requirements are redundant. Recommend combining R9. and R10 and ending the new requirement with "as appropriate." Also, the UFLS program should have been developed by the Reliability Assurer rather than the Planning Coordinator. **Response**: Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Operator; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding. Therefore, the team decided not to merge the two requirements. The team modified Requirement R10 to clarify that it means: "switching of capacitor banks, Transmission Lines, and reactors" to control over voltage as a result of under frequency load shedding. R11. Change Planning Coordinator to Reliability Assurer. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5.

Voter	Entity	Segment	Vote	Comment
				R12. Change Planning Coordinator to Reliability Assurer. R13. Change Planning Coordinator to Reliability Assurer. R14. Change Planning Coordinator to Reliability Assurer. Recommend developing a requirement for the Reliability Assurer to provide a comment period within the time frames established in their bylaws. C. Measures - Our comments to the Measures are comparable to the comments on the Requirements with regard to entities involved. Where requirements are suggested in the comments to be removed, the accompanying measure needs to be removed. D. Compliance 1.1 - Add NERC to monitor Reliability Assurer compliance. 1.2 - Change Planning Coordinator to Reliability Assurer in all instances. Requirements that we propose removing would be removed from data retention requirements. **Response**: Instead of assigning responsibility to the Reliability Assurer the standard drafting team revised Requirements R5 and R13 to define a set of actions that are measureable that will demonstrate that Planning Coordinators worked together should an island span more than one Planning Coordinator area. The standard drafting team confirms that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5. Violation Severity Levels (VSLs) The VSL references to Planning Coordinator should be changed to Reliability Assurer. VSLs for Requirements previously recommended for removal can be removed. R11. What violation does the “Lower VSL” indicate? R12. What is the true significance behind going from Moderate VSL to Severe VSL in a matter of two months when there is a two year period for the design assessment? R14. The UFLS program developer should respond to all comments before UFLS program implementation. Recommend High VSL if i **Response**: The drafting team has posted its justification for assignment of VSLs – the justification identifies how the VSLs meet the NERC and FERC guidelines for setting VSLs.
Response: A regional variance for the WECC interconnection has been included which should also address several of these concerns.				

Voter	Entity	Segment	Vote	Comment
Ralph Frederick Meyer	Empire District Electric Co.	1	Negative	Prefer that a reliability standard requirement should to an entire entity class (per the Functional Model) not some sub-set of that entity. However, if the SDT determines to keep as indicated in this version, then we suggest that section 4 be revised to add clarity. Without the benefit of the background information above, the intent of the language in 4.2 and 4.3 could be lost. We suggest that section 4.2 be revised to read "UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment or automatic switching of Elements as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers" and that 4.3 be deleted.
Response: Requirement R9 focuses on automatic tripping of load and may be performed by either the Distribution Provider or the Transmission Owner; Requirement R10 focuses on switching of devices to control over-voltage as a result of under frequency load shedding by the Transmission Owner (only). The switching of elements is generally performing at higher voltages than distribution voltages and as a result decided to not include the Distribution Providers in Requirement R10.				
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Negative	R14 is procedural and not appropriate for a reliability standard R11 should not be for just any UFLS events (e.g., small local area events with few or no generators in the island), but should include all disturbance events as defined in EOP-004 that should be studied. This standard is too complicated. It could be simplified to the following requirements; it should require a documented Planning Coordinator (PC) UFLS plan, data should be provided to the PC, PC should determine design characteristics, and verify through simulation that the plan works as designed.
Response: Peer review procedures such as R14 are used elsewhere in approved NERC standards, specifically FAC-010 and FAC-011. The procedure has industry support. It allows Transmission Owners and Distribution Providers to at least have some say in what they will be obligated to implement. The scope of the commenter's suggestion on R11 goes beyond what is necessary for UFLS purposes. The SDT disagrees that this standard is too complicated. The requirements are necessary for reliability of UFLS programs. The commenter's overall suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, there would be no coordination between adjacent Planning Coordinators, no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays.				

Voter	Entity	Segment	Vote	Comment
Douglas E. Hils	Duke Energy Carolina	1	Negative	Requirements R5 and R13 contain the problematic requirement to "reach concurrence", as discussed in our responses to the comment form. One way to address this concern would be to revise R5 and R13 to require affected Planning Coordinators to share design assessment results and event assessment results and respond to technical questions/comments within a prescribed time period.
Response: The SDT has modified R5 and R13 to reflect the intent that only UFLS programs within the PC areas that are a part of the island under study need to work in conjunction to meet the performance requirement in R3. The SDT also modified R5 and R13 to remove the "concurrence" requirement and provide a means by which each PC can meet this requirement alone or by working with other PCs.				
Tom Bowe	PJM Interconnection, L.L.C.	2	Negative	SDT must define "design assessment". Is it different from every other one of the other assessments conducted by the PC? Without clarification an RE is left with these questions: Is the requirement to conduct an assessment? Or is it to conduct an assement that sucessfully meets R3? Is the PC non-compliant when its area's assets can not resolve the studied condition? Additionally, R12 is unclear in what it means by "event actuation". Is the objective to run an assessment; or is the objective to "design" a solution to islands created during a planning assessment. Clarify meaning of event actuation. R11 can be read to mean "when that event occurred in the real system (i.e. was actuated) then an event analysis must be considered; or it can mean when an assessment shows the creation of an island, then the PC must devise a process or procedure to correct the incident within 1 year. The text is awkward.
Response: The objective of the design assessment is to verify that the design of the UFLS program satisfies R3. For the purposes of PRC-006, the design assessment needs to be distinguished only from the event assessment, which is an after-the-fact analysis of a UFLS event per R11. There are no other assessments required by this standard. It is required to conduct an assessment that shows the UFLS program design satisfies R3 for each of the identified islands from R2. A PC would be non-compliant if its UFLS program cannot satisfy the performance curves in the Attachments up to a 25 percent imbalance between load and generation while considering the sub-points specified in R4. The objective of the event assessment is to analyze events after-the-fact. Event actuation is the time when the event was initiated. The point of R12 is to follow up after an event assessment if the event assessment indicated that the UFLS program did not perform as well as expected, or that improvements may be possible. It is not required that improvements be made, only considered. R11 means "when that event occurred in the real system (i.e. was actuated) then an event analysis must be considered." The PC does not need to "devise a process or procedure to correct the incident within 1 year," though a PC may consider changes to the UFLS program design that might improve its performance in future events of a similar nature in R12.				

Voter	Entity	Segment	Vote	Comment
Mark Ringhausen	Old Dominion Electric Coop.	4	Negative	See my comments in the VRF/VSL ballot.
Response: Please see the SDT response to your comments in the VRF/VSL non-binding poll.				
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Negative	See WECC comments
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	Several issues still need to be addressed in previously submitted comments. 2. This standard is too complicated and should be simplified to the following requirements; a documented Planning Coordinator (PC) UFLS plan, data provided to the PC, the PC should determine minimum design characteristics, entities should verify through simulation that the plan works as designed, and entities should provide their plan to adjacent interconnected NERC registered entities as evidence of coordination. 3. The performance curves the attachments should clearly state what approximately expected loss of life is being imposed on generator owners / operators to meet the curve expectations. Is the Generator under frequency trip model curve expecting a 5% or 10% loss of life probability per under frequency event for each unit? Generator Owners / Operators need to understand what kind of risk a standard imposes to make decisions on how best to comply with NERC standards, even if that decision is simply whether to change unit settings to meet a proposed curve or not.
Response: 1. Please see SDT response to previously submitted comments. 2. The SDT disagrees that this standard is too complicated. The requirements are necessary for reliability of UFLS programs. The commenter's overall suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, there would be no coordination between adjacent Planning Coordinators, no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays. 3. This is a subject for Project 2007-09 and the PRC-024-1 SDT. This standard is not applicable to Generator Owners. Loss of life depends on both the specifics of events and the specific characteristics of individual generators; the question is not one that can be answered with any certainty.				
David Schiada	Southern California Edison Co.	3	Negative	Support concerns identified by WECC.

Voter	Entity	Segment	Vote	Comment
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Keith Morisette	Tacoma Public Utilities	4	Negative	Tacoma Power is voting negative. We agree with the WECC position paper, which emphasizes that the UFLS should be focused on keeping the interconnection stable and not focusing on islands. The western interconnection currently has a single coordinated plan with support from its subregions. We continue to support this plan as the requirement for the interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Karl Bryan	U.S. Army Corps of Engineers Northwestern Division	5	Negative	The applicability section should list the Registered Entities that the Reliability Standard applies to. The approach used in this proposed reliability standard will lead to confusion.
Response: The SDT believes that the “UFLS Entities” approach is necessary in a continent-wide standard to accommodate the variety of historical practices in what entities implement UFLS.				
Alan Gale	City of Tallahassee	5	Negative	The attempt to define "annual" in R6 forces me to maintain my negative vote. The definition of "annual" is a very touchy subject. It determines compliance or non-compliance in a lot of standards. For those entities that have defined it internally, we are trying to impart some "defenition" to our procedures and policies. This issue is important enough that it should NOT be a last minute addition to a "second ballot" that was changed to reach concensus on all other issues. It should be defined above board and by a separate SAR if the SDT feels so strongly. I believe the commenter that asked about it was trying to find out what the "maintain" portion was refering to, not hte "annual".
Response: The change from “annual” to “at least once each calendar year, with no more than 15 months” was made merely to indicate what was intended by the term “annual”. This was a clarification from the previous posting of the standard to aid PCs in their interpretation of the requirement.				

Voter	Entity	Segment	Vote	Comment
William Mitchell Chamberlain	California Energy Commission	9	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. **Response**: A regional variance for the WECC interconnection has been included which should address these concerns. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. **Response**: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; “For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been

Voter	Entity	Segment	Vote	Comment
				provided. **Response**: Interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1.
Response: Please see the in-line responses.				
Ronald D. Schellberg	Idaho Power Company	1	Negative	The current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. WECC had a disturbance the was negatively impacted by the lack of cordination of UFLS between subregions. Continent wide Frequency-time curves would not account for the interconnection size.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Laurie Williams	Public Service Company of New Mexico	1	Negative	The current proposal still does not require coordination within the interconnection. The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As written the proposed standard creates the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement

Voter	Entity	Segment	Vote	Comment
John Tolo	Tucson Electric Power Co.	1	Negative	a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. BCH believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Joel T Plessinger	Entergy	3	Negative	The following are the reasons associated with our Negative Ballot. Entergy reserves the right, after review of all the submitted ballots, to join with other balloters, whether positive or negative ballots, where any reasons included in their ballot that may be applicable to or otherwise impact Entergy as related to this ballot. All of the following Reasons are directed at the revisions applied to PRC-006-1. We agree with the EOP-003-1 revisions. In M3 it is unclear what action is intended by the phrase "including the criteria itself". Since the criteria is specified in R3, it is recommended that the phrase be deleted. R5 and M5 should only apply to Planning Coordinators (PC) who are part of the joint island, while the way it is currently worded it appears to apply to every PC. We recommend the wording in M5 be changed to: "Each Planning Coordinator shall have dated evidence such as memorandums, letters, or other dated documentation that it reached concurrence with the other affected Planning Coordinators on design assessment results for any

Voter	Entity	Segment	Vote	Comment
				identified island in accordance with Requirement R5 and identifies the affected Planning Coordinators." We also recommend that the wording in R5 be changed to: "Each Planning Coordinator shall reach concurrence with all other affected Planning Coordinators in UFLS design assessment results before design assessment completion for any island identified by that Planning Coordinator which include a portion of its footprint along with portions of another PC(s) footprint." The Lower VSL for R11 appears to simply repeat the requirement rather than stating a violation. We recommend that the time ranges for the VSLs addressing being late with the assessment should be expanded to Moderate - 12-14 months, High - 14-16 months, and Severe - greater than 16 months. We also recommend that the High and Severe VSLs that contain the phrase "shall conduct and document" to read "conducted and documented". The VSLs for R4 should include a consideration of the timeliness of the completion of the study (e.g. Lower VSL for 3 months late, Moderate VSL for 3 to 6 months late, etc.) The standard R5 requires that both or all the Planning Coordinators agree. One PC might have larger margin requirements or a different methodology compared to another PC. These differences might not be reconcilable. We do not believe that a standard can require that one PC change its methods because a different PC does not agree with its methods, or agree that another method (any method) is acceptable that it finds a problem with. There at least needs to be a process in the event that two PCs cannot agree. We recommend that the following language be added to R5: "If concurrence cannot be reached, an individual Planning Coordinator in that island can demonstrate that its UFLS scheme meets the requirements by performing dynamic simulations that apply its UFLS scheme on the entire island." We recommend that R13 be eliminated since it is covered by R11. We recommend that R3 be revised to require the PC to specifically notify each of the "UFLS Entities" in their PC area that are part of the PC's UFLS program of the UFLS program. We are also concerned that the Planning Coordinator is responsible to develop a UFLS program that incorporates information from Generator Owners (R3-R3.3.3) but there is no requirement that Generator Owners

Voter	Entity	Segment	Vote	Comment
				provide this information. We are aware that PRC-024 (Project 2007-09) contains reporting requirements (R3, R4 and R5) but are not certain that the tables in PRC-024 match those in PRC-006 nor is there any guarantee that PRC-024 will be FERC approved without change. Therefore, we request that this standard be made applicable to GOs and those GOs provide the required information. The Unofficial Comment Form for this standard, in the Review of Technical Changes to Standard section contains the following statement "The SDT has added requirements to include an assessment of the performance of UFLS programs "within one year of an actuation of UFLS resulting in 500 MW or greater of loss of load."(Requirement R11)." However the 500 MW limitation is not included in R11. We recommend this 500 MW limitation be added to R11. There is no need to evaluate smaller islanding events.
Response: The SDT agrees and has modified M3 to remove the phrase "including the criteria itself". The SDT has modified R5 and M5 to reflect the intent that only UFLS programs within the PC areas that are a part of the island under study need to work in conjunction to meet the performance requirement in R3. The SDT also modified R5 and M5 to remove the "concurrence" requirement and provide a means by which each PC can meet this requirement alone or by working with other PCs. The SDT has modified the VSLs for R11 to make these corrections. The SDT considered this and decided that the program reassessment is a binary task which automatically makes this a severe violation if not completed within the 5 year timeframe. The SDT has modified R13 to eliminate any duplication between R13 and R11. Requirement R3 has been modified to specifically indicate that the UFLS program must include "**notification** of and a schedule for implementation" in support of your suggestion. The SDT has added R14 which now requires the UFLS entities be notified of a comment period and for the PCs to respond to those comments prior to a UFLS program becoming effective. The SDT modified the implementation plan to state, "Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1." Per the implementation plan, the requirement to model data from the GOs is not mandatory until after the GOs are required to provide the data by PRC-024. This is similar to the requirement to model the BES by the TPL standards, while the requirement by entities to provide the data used to model the BES is contained in the MOD standards. The existing standard PRC-009, which this standard is intended to replace, currently requires that an assessment be performed for all events regardless of size. The SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the requirement the same or better than what exists today.				
Kim Warren	Independent Electricity System Operator	2	Negative	The IESO maintains its NEGATIVE vote in this ballot for the following main reasons: Criteria for Selecting Generators for Simulation Modeling

Voter	Entity	Segment	Vote	Comment
				Requirement R4 defines criteria for identifying generating units to be included by the Planning Coordinator (PC) in its periodic UFLS design assessment however we believe these criteria are insufficient. In response to other commenters the SDT stated "The SDT believes that there is a relatively small percentage of generation that is not registered and also has frequency trip settings that do not conform with curves of Attachment 1." We are concerned about this assumption regarding the effectiveness of the NERC 20/75 MVA criteria since this is untrue in Ontario. In Ontario at least 2600 MW of generation (about 10% of generation in Ontario) would currently not be covered by these criteria and this amount is expected to increase as a result of provincial generation procurement initiatives. It is doubtful whether it would be possible to design an effective UFLS program with this much uncertainty. With increased penetration of renewable energy sources many of which may fall below the 20/75 MVA threshold, this problem is likely not unique to Ontario. We therefore believe the NERC standard needs an explicit mechanism for PCs to impose more stringent requirements when necessary to achieve the purpose of the standard. Generator Frequency Trip Curves The IESO was not satisfied with the SDTs response to our comment regarding evidence supporting the need for the overfrequency trip modeling curves proposed in this standard. We would also like to see similar justification for the underfrequency trip modeling curves. Although these curves have been proposed in PRC-024 and have not yet been approved, they are nevertheless referenced in the version of PRC-006-1 currently posted for ballot. Our concern is that these unapproved curves directly impose constraints on the Planning Coordinator in the design of its UFLS program. Imposing an unsubstantiated overfrequency constraint may cause unnecessary generator tripping, and may seriously interfere with the ability of PCs to develop a practical ULFS program particularly in light of the issues surrounding applicability mentioned above. We believe these two interdependent standards should either go to ballot together so that any issues regarding the curves could be adequately ventilated or PRC-006 should be changed to remove coupling to PRC-024. In brief, a standard should not be balloted when it depends on the information/requirement in another standard which has not been developed/approved. Gradual Decline in Reliability Standards Experience in NPCC working groups in this matter has shown it will be difficult to hold on to more stringent Regional or Area standards with PRC-006 in its present format.

Voter	Entity	Segment	Vote	Comment
				For example the NPCC generator underfrequency “do-not-trip” curve is lower (more onerous) than that required by NERC. Within the NPCC UFLS standard drafting team there was a natural tendency to harmonize the NPCC draft UFLS standard with the draft NERC PRC-006 curve, rather than to maintain NPCC’s more stringent approved criteria (Directory #12). While such sentiments have not prevailed thus far, if the NERC standard is passed in its present format, weakening of the NPCC standard would be inevitable with the unintended consequence of reduced reliability in the NPCC portion of the Eastern Interconnection.
Response: A regional variance can and should be considered by IESO. A variance could be more stringent than the level of detail and the adaptability to local conditions that a continent-wide standard can practically attain. Justification for both over and under frequency generator tripping curves is from manufacturer’s recommendations on acceptable durations at high and low frequencies. The curves were also chosen in recognition of existing legacy region guidelines on generator durations. These curves will become approved upon the approval of either PRC-006 or PRC-024, which ever is approved first. Further information on curve justification, or the need to modify a curve, should be asked of the PRC-024 SDT. The two teams have coordinated to the degree necessary to establish consistency, but cannot impose on each others schedules. The situation of interdependence of standards is not unique to PRC-006 and PRC-024. For example, compliance to TPL standards is dependent on system modeling data required under MOD standards. There is a limit as to what a continent-wide standard can achieve for the reliability concerns of an area without unduly imposing constraints on other areas that do not need tighter constraints. A variance may be the appropriate mechanism for addressing IESO’s concerns.				
Donald S. Watkins	Bonneville Power Administration	1	Negative	The primary concern identified in the first position paper is that the proposal does not require coordination within individual interconnections. The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is

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Dana Cabbell	Southern California Edison Co.	1	Negative	problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. WECC believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
John Canavan	NorthWestern Energy	1	Negative	The primary concern identified is that the current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. **Response**: A regional variance for the WECC interconnection has been included which should address these concerns. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. **Response**: The SDT recognizes that the Functional Model Version 5 and the Statement of Compliance Registry cause confusion regarding the involvement of the LSE in UFLS programs but the SDT refers to the section covering the Roles in Load Curtailment in Version 5 of the Functional Model Technical Document; "For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer
John C. Collins	Platte River Power Authority	1	Negative	
Terry L Baker	Platte River Power Authority	3	Negative	
Glen Reeves	Salt River Project	5	Negative	

Voter	Entity	Segment	Vote	Comment
				loads should be excluded from curtailment for public health, safety and/or security reasons. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided. **Response**: Interconnection coordinated UFLS plans are desirable, but the degree of diversity of systems in various regions, particularly in the Eastern Interconnection, makes this an unrealistic goal for a continent-wide standard; some flexibility needs to be reserved to address regional needs. The SDT believes that there is confusion concerning the application of the curves. The goal of the UFLS is to control frequency during a UFLS event such that generation does not trip. Project 2007-09 Generator Verification for draft Standard PRC-024 is developing the curves to establish the over- and under-frequency protection for the generation, so, the UFLS SDT is trying to stay within those curves by some margin, e.g., between the two curves of Attachment 1.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Tim Kelley	Sacramento Municipal Utility District	1	Negative	The primary concern identified is that the proposal does not require coordination within individual interconnections. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of “competing” uncoordinated underfrequency load shedding programs for a single event.
James Leigh-Kendall	Sacramento Municipal Utility District	3	Negative	
Mike Ramirez	Sacramento Municipal Utility District	4	Negative	

Voter	Entity	Segment	Vote	Comment
Bethany Wright	Sacramento Municipal Utility District	5	Negative	
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Michael J. Haynes	Seattle City Light	5	Negative	The primary concern identified is that the proposal does NOT require coordination within individual interconnections. The standard references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. The standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within RROs to adopt the Off-Nominal Frequency Load Shedding and Restoration Plans, modified as may be necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within interconnections.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Negative	The primary concern is that the current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Jerome Murray	Oregon Public Utility Commission	9	Negative	The proposed standard does not require coordination within individual interconnections. The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning

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				Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of "competing" uncoordinated underfrequency load shedding programs for a single event. The standard needs to require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. For example, this would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Scott Kinney	Avista Corp.	1	Negative	The proposed standard does not require coordination within the interconnection. The standard should require the PCs within an interconnection to develop a coordinated UFLS plan.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Jerry W Johnson	South Mississippi Electric Power Association	5	Negative	The requirement seems to require the installation of facilities rather than just relays. 16 USC 824o (a)(3) gives NERC the authority to regulate existing facilities and planned additions or modifications to those facilities, not to prompt or require modifications or additions to the existing facilities. Criteria are never actually defined in the requirements. Planning Coordinator footprints are not established. What does "annually maintain" mean? Does it mean the Database requires annual updates, annual reviews or just to provide a database annually? Frequency excursions precede an islanding event. I.e. low frequency initiates UFLS which should prevent an unintentional islanding event. The wording of this requirement makes it seem like the islanding event occurs first and causes the UF. Measures are too vague, lacking specifics, and not performance-based.

Voter	Entity	Segment	Vote	Comment
				This would leave too much up to the Auditor's interpretation. Measures are only valuable if they contain specific targets or specifications that clarify how an entity will be deemed to be compliant with the standard as written. Measures which merely repeat the standard with the inclusion of "shall have evidence such as..." are not very useful. Measures should be explicit, detailed, consistent, and provide useful guidance to entities. These measures do not provide any useful guidance beyond what is specified in the requirement itself. M3: It is unclear what action is intended by the phrase "including the criteria itself." Since the criteria is specified in R3, it is recommend that the phrase be deleted. M5 and R5: This should only apply to PCs who are a part of the joint island, while the way it is currently worded it appears to apply to every PC. The graphical representation of the frequency-time curves alone allows plenty of margin for mis-interpretation of the curves data points. A "break-down" of the plotted curves should be clearly displayed (in conjunction with the graphical curve representation) in a table immediately below each frequency-time curve to further clarify the under- and over-frequency performance characteristic curves data points The standard lacks guidance as to what the trip settings should be. It is not clear as to how Attachment 1 should be used and doesn't provide specific detail for under frequency set points. Neighboring Planning Coordinators will be making requests and setting criteria for the local planning coordinators and associated UFLS entities. We do not agree with the text "any Planning Coordinator may now select islands including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, without the need for coordinating." It is not clear what is included in automatic switching. This requirement is so vague that it does not appear to add anything in addition to the UFLS program design that it is intended to address. It appears that anything that R10 may be designed to address is already covered by R9.
Response: This standard is not out of line with expectations for standards in general. The proposed standard does not require the installation of facilities or relays. The SDT clarified this by adding the word "existing" in front of capacitor banks, Transmission Lines, and reactors in Requirement R10 to clarify that the intent. The SDT disagrees that the jurisdiction of Planning Coordinators and their footprints has not been established. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. Annually maintain means annual updates, though				

Voter	Entity	Segment	Vote	Comment
not exclusively. The term “annual’ has been replaced with wording that is more specific. UFLS cannot be expected to mitigate island formation. Most interconnections are large enough that a decline in frequency low enough to cause UFLS operations is highly unlikely unless the interconnection is broken into islands. Most UFLS operations are seen to occur following island formation. R5 has been clarified to address the commenter’s concern. Attachment 1 now has the performance characteristic curve data points tabulated. The under and over frequency performance curves are solely for checking frequency trajectories in dynamic simulations of UFLS program performance and should not be misconstrued as applying to UFLS relay set points. UFLS entities are not affected, nor will a Planning Coordinator need to make requests of them or set criteria for them as far as island identification is concerned. The SDT believes the text quoted by the commenter is necessary due to the wide range of island determination criteria (R1) that may be forthcoming. “Automatic switching of Elements” refers to switching of, among other Elements, cap banks to prevent excessive voltages. R10 has been modified to remove the confusion.				
Richard J. Padilla	Pacific Gas and Electric Company	5	Negative	The revised proposal still does not require a coordinated plan within the interconnection to eliminate islands. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. Further refinements or additional requirements to an Interconnection's Coordinated plan can be made to address scenarios that can cause islands as determined by studies that are made at the overall Interconnection level. The draft standard is also very prescriptive is some cases, going as far as specifying maximum Volts per Hertz limits in simulated studies of islanded scenarios, as well as frequency versus time envelopes or boundaries that specify acceptable over/under frequency excursions. These type of performance limits should be specified at the Interconnection level based on the characteristics of the Interconnection, not at the National level. The proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. The proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common

Voter	Entity	Segment	Vote	Comment
				denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Gregory J Le Grave	Wisconsin Public Service Corp.	3	Negative	The Standard is not ready for implementation because portions of the draft are difficult to interpret due to vague language. R5 and R13 use the phrase "reach concurrence". In addition, it isn't clear if the UFLS entities must have the Planning Coordinator's UFLS program implemented by the standard's effective date.
Response: Some of the more vague wording had been replaced with wording that is more specific such as in R7 and R10 in the previous draft. The SDT agreed that reaching concurrence could be problematic and modified R5 and R13 to address this concern in the previous draft and eliminated the phrase, "reach concurrence" in support of your suggestion. UFLS Entities only need to comply with the Planning Coordinator's schedule for application; the Implementation Plan does not apply to the UFLS Entities. (Please see Implementation Plan Proposed Effective Date)				
Mel Jensen	APS	5	Negative	The standard is too prescriptive. It requires that islands be formed and the underfrequency load shedding be designed to arrest the frequency in the islands and meet several requirements. While this is a valid approach, it is a very restricted and prescriptive approach. The islands formed in the study may not be the islands which actually form when the events happen. The under frequency load shedding scheme should be considered as a safety net and the Planning Coordinator should be given more flexibility. Most of the standard requirements should be guidelines.
Robert D Smith	Arizona Public Service Co.	1	Negative	
Response: A continent-wide standard can specify performance curves or it can specify UFLS design parameters; the SDT has opted for performance curves. This is the less prescriptive approach of the two. The standard does not require island formation, only identification of islands to serve as the basis for UFLS assessments. The standard does not require Planning Coordinators to predict islands that may occur in the future; it only requires criteria for island identification in order for the design assessments in R4 to be conducted. UFLS needs to arrest system frequency declines, whether as islands or the interconnection. Guidelines have no place in an enforceable standard. A continent-wide standard must identify requirements that are common to the four interconnections and the SDT believes the standard does that without being unnecessarily prescriptive.				

Voter	Entity	Segment	Vote	Comment
John Yale	Chelan County Public Utility District #1	5	Negative	The standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would ensure continued coordination for underfrequency events within each interconnection and prevent individual PCs from developing conflicting plans.
Chad Bowman	Public Utility District No. 1 of Chelan County	1	Negative	
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Frank F. Afranji	Portland General Electric Co.	1	Negative	The standard should require coordination of UFLS plans not merely allow it. We agree with the WECC position paper which elaborates on this coordination. UFLS coordination should occur at the regional level, not the Planning Coordinator level.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Dennis Sismaet	Seattle City Light	6	Negative	The standard, requirements, and measurements should reflect the uniqueness of the individual interconnections and not common, continent wide prescriptions. The primary concern identified in the first position paper is that the proposal does not require coordination within individual interconnections. The current version of the standard would allow for all of the Planning Coordinators (PCs) within an interconnection to agree upon and implement a single coordinated plan, but it does not require it. As worded, the proposed standard would still allow for the possibility of as many different UFLS plans within an interconnection as there are Planning Coordinators. The standard still references islands that could form within the interconnection. There is no guarantee that islands that could form will form for all situations. The possibility of activation of multiple underfrequency programs intended to address islands that could form is problematic. Without the requirement to ensure coordination between the programs, if unanticipated islands form or no islands form, the result could be the activation of “competing” uncoordinated underfrequency load shedding programs for a single event. WECC believes that the standard should require a coordinated plan for each interconnection. Each interconnection has distinct characteristics that will require different plans. A single continent-wide performance characteristic could be achieved by different coordinated interconnection plans. This would allow all the PCs within WECC to adopt the existing WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, modified as may be

Voter	Entity	Segment	Vote	Comment
				necessary to meet the continent-wide performance curves of the continent-wide standard. This would ensure continued coordination for underfrequency events within the Western Interconnection.
Response: A regional variance for the WECC interconnection has been included which should address these concerns.				
Michelle Rheault	Manitoba Hydro	1	Negative	This standard is not ready for ballot. See submitted comments.
Mark Aikens	Manitoba Hydro	5	Negative	
Daniel Prowse	Manitoba Hydro	6	Negative	
Response: Please see the response to your submitted comments.				
Pawel Krupa	Seattle City Light	1	Negative	This standard needs more work to define the areas that need an UFLS program, and who coordinates the programs.
Dana Wheelock	Seattle City Light	3	Negative	
Hao Li	Seattle City Light	4	Negative	
Response: The SDT has made conforming changes to the proposed standard. The SDT is leaving it up to the Planning Coordinators to develop the UFLS program requirements for their Planning Coordinator area.				
Michael Moltane	International Transmission Company Holdings Corp	1	Negative	To meet requirement R4 as written, we will need generator frequency relay data that will be required in the new PRC0024 which is not yet approved. The generator Owners need to be required to provide this data to the Planning Coordinator in this standard.
Response: The SDT recognizes that PRC-024 may be approved at a different time and has inserted a provision in the implementation plan document to account for that possibility. Generator applicability is deferred to PRC-024 to avoid double jeopardy.				
Linda Horn	Wisconsin Electric Power Co.	5	Negative	We appreciate the SDT adding R14 in an attempt to provide a feedback mechanism between the UFLS Entity and the Planning Coordinator

Voter	Entity	Segment	Vote	Comment
James R. Keller	Wisconsin Electric Power Marketing	3	Negative	regarding the UFLS program design. However, the UFLS program which is ultimately implemented by the UFLS Entity needs to be mutually agreed to between the Planning Coordinator and the UFLS entity. Requirements R9, R10, and R14 must be strengthened to reflect as such. The "mutually agreed to" concept would force checks/balances in the development of the UFLS program to avoid unfairly burdening a UFLS Entity while maintaining reliability. We continue to believe that only islands of significant size be considered for the design of a UFLS program and for simulation after an UFLS event. The SDT stated in its consideration of comments that "PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009." We believe that the SDT can place a threshold in the revised PRC-006 since it is replacing PRC-009.
Response: A requirement for entities to mutually agree with each other or work together causes one entity's compliance to be dependent on another's. This has generally been viewed as unacceptable by the industry. This standard does not preclude development of regional standards in a process that may involve all interested entities in the region. PRC-009, which R11 is due to replace, is already a FERC approved standard and requires an assessment for all events regardless of size. An SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the standard the same or better than what exists today. We have specific feedback from FERC that they would not approve PRC-006 with an event analysis threshold because they would view that as lowering the bar. Note that identification of islands for UFLS design assessments may use whatever threshold a Planning Coordinator believes is appropriate in satisfying R1.				
Anthony Jankowski	Wisconsin Energy Corp.	4	Negative	We appreciate the SDT adding R14 in an attempt to provide a feedback mechanism between the UFLS Entity and the Planning Coordinator regarding the UFLS program design. However, the UFLS program which is ultimately implemented by the UFLS Entity needs to be mutually agreed to between the Planning Coordinator and the UFLS entity. Requirements R9, R10, and R14 must be strengthened to reflect as such. The "mutually agreed to" concept would force checks/balances in the development of the UFLS program to avoid unfairly burdening a UFLS Entity while maintaining reliability. We continue to believe that only islands of significant size be considered for the design of a UFLS program and for simulation after an UFLS event. The SDT stated in its consideration of comments that "PRC-009, a FERC approved standard, does not have an event threshold, and PRC-006 is absorbing PRC-009." We believe that the SDT can place a threshold in the revised PRC-006 since it is replacing PRC-009.

Voter	Entity	Segment	Vote	Comment
				We expressed a concern that the standard could place a burden on the UFLS Entity to shed additional load to make up for generators that do not conform to the PRC-006/PRC-024 underfrequency/overfrequency tripping curves. "The SDT has addressed the matter of GO versus TO/DP obligation for non-conforming generators and has decided that, for the likely small amount of non-conforming generation, that it should be a small burden, if any, to be spread across multiple TO sand DPs." We do not believe that ignoring GO responsibilities due to possible small burden is acceptable, as in some areas the burden may be significant and unwarrented without an obligation on the generator.
Response: A requirement for entities to mutually agree with each other or work together causes one entity's compliance to be dependent on another's. This has generally been viewed as unacceptable by the industry. This standard does not preclude development of regional standards in a process that may involve all interested entities in the region. PRC-009, which R11 is due to replace, is already a FERC approved standard and requires an assessment for all events regardless of size. An SDT cannot remove a requirement from an existing standard without a technical justification that explains how this will make the standard the same or better than what exists today. We have specific feedback from FERC that they would not approve the standard with a threshold because they would view that as lowering the bar. Note that identification of islands for UFLS design assessments may use whatever threshold a Planning Coordinator believes is appropriate in satisfying R1. On the question of Generator Owners versus UFLS Entities assuming the burden of non-conforming generators, the SDT had discussed this matter at length at an early stage in development of this standard and believed that the amount of non-conforming generation would be small because the generator tripping curves (Attachment 1) have been chosen based on the off-nominal frequency duration recommendations of major generator manufacturers and were also chosen in recognition of legacy region guidelines on generator tripping.				
Kathleen Goodman	ISO New England, Inc.	2	Negative	We believe that the applicability section, which states: UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following: 4.2.1 Transmission Owners 4.2.2 Distribution Providers Excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This appears to be a missing link that needs to be addressed before the standard can be approved. Also, the standard is potentially in conflict with the work to be done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. This would present yet another example of lack of coordination on NERC Standards development.
Response: The draft of PRC-024-1 is applicable to Generator Owners and will have the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. Generator applicability is deferred to PRC-024 in order to avoid double jeopardy for				

Voter	Entity	Segment	Vote	Comment
Generator Owners. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. The SDT has coordinated with the PRC-024 SDT so that both PRC-006 and PRC-024 are using the same under and over frequency generator tripping curves.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	While we agree with the purpose statement of the draft UFLS standard, we are voting negative. First, the standard goes much farther than the purpose statement. It is too prescriptive and includes too many administrative requirements. The new R14 is completely an administrative requirement that establishes a stakeholder process which has no reliability benefit. Furthermore, FERC Order 890 already requires transmission planners and planning coordinators to develop a stakeholder process. We agree that it makes sense to develop a frequency envelope to ensure it is coordinated across the Interconnection but question the need for Volts/Hz limit in 3.3. Secondly, the standard is overly complex. UFLS relays already are installed and coordinated today. The standard needs to reflect this reality and be made simple. We believe the standard should not be more complicated than establishing a requirement to have coordinated UFLS relays and making pertinent information available on the UFLS relays and program to the reliability entities with a need to know. The purpose can be accomplished in many fewer requirements than the 14 proposed requirements. Thirdly, we do not agree with the need to identify islands. While some areas of the BES have obvious islands such as the Florida peninsula, most of the BES does not form obvious islands and trying to predict how islands will form is arbitrary and unnecessary and provides no clear benefit to reliability. Other requirements that build on this islanding concept are unnecessary as well. For instance, we do not believe it is necessary or even beneficial to perform dynamic simulations of the UFLS program in areas that do not have natural islands. These simulations involve contingencies to such extremes that it stretches the limits of the analysis software and provides arbitrary results with questionable value. While these studies have been attempted in the past, some of these very studies have stated within their documentation that the island boundaries are completely arbitrary and don't correspond to any historical or conceivable islanding event. Furthermore, an effective UFLS scheme can be designed without simulations.
Response: Several commenters have expressed concerns that a Planning Coordinator can devise a UFLS program design and implementation				

Voter	Entity	Segment	Vote	Comment
schedule without any consideration of input by Distribution Providers or Transmission Owners before those plans are finalized. R14 establishes a peer review to at least partially address those concerns. Peer review procedures such as R14 are used elsewhere in approved NERC standards, specifically FAC-010 and FAC-011. The procedure has industry support. It allows Transmission Owners and Distribution Providers to at least have some say in what they will be obligated to implement. The Order 890 stakeholder process does not cover UFLS. Excessive V/Hz may cause unnecessary tripping of generation that may exacerbate an already precarious underfrequency condition. The SDT believes that this threat to UFLS effectiveness should not be overlooked. The SDT disagrees that this standard is too complicated. The requirements are necessary for reliability of UFLS programs. The commenter's suggestion to simplify would not establish reliability criteria for UFLS programs to achieve, there would be no coordination required between adjacent Planning Coordinators, no coordination with generator tripping, no protection against generator tripping due to high V/Hz, no necessity to analyze underfrequency events, and no requirement for anyone to install and set UFLS relays. Islands, whether arbitrary or real, need to be identified in order to conduct UFLS design assessments. The SDT agrees that effective UFLS can be designed without simulations, but that is not the only means. Simulations are necessary to at least supply the evidence that a UFLS design can be effective.				
Paul Rocha	CenterPoint Energy	1	Negative	With regards to the proposed PRC-006-1; CenterPoint Energy is concerned about the overly prescriptive nature of this proposal and cannot support it in its present form. In particular, a requirement to identify areas that "may Island" might, arguably, make sense for a large interconnection such as the eastern or western interconnect, but it makes no sense for a smaller interconnect such as ERCOT that, essentially, is already an island for the purposes of this standard. Even for the larger interconnections, there are limitless possibilities of potential "islands" that could occur given certain combinations of contingencies. Since it is impractical to identify every conceivable island, it is unclear what level of diligence and documentation would be required to demonstrate to an auditor's satisfaction that the responsible entity has reasonably identified areas that "may" island. This ambiguity and subjectivity is contrary to objective number 2 in the Project Background to develop a standard "with clearly defined requirements and unambiguous language".
Response: All that is required concerning island identification (R1, R2) is to devise some criteria considering historical events and system studies and use those criteria to identify some islands. This does not mean that every conceivable island must be identified. The criteria can be as simple or elaborate as a Planning Coordinator desires. The SDT does not believe this is overly prescriptive, nor does it believe that it is ambiguous. However, island identification is admittedly subjective and it is difficult to offer more specific guidance in the standard without limiting flexibility and adaptability to characteristics specific to a region or interconnection.				
Gregory L Pieper	Xcel Energy, Inc.	1	Negative	Xcel Energy believes that the standard still contains many issues that are not clear and need to resolved. Among these issues is the mapping of PC to subordinate entities in areas where a regional entity or RTO has not
Michael Ibold	Xcel Energy, Inc.	3	Negative	

Voter	Entity	Segment	Vote	Comment
Liam Noailles	Xcel Energy, Inc.	5	Negative	taken on the PC role. Also, there are concerns around how small generators (less than the threshold specified) are addressed. Detailed comments were submitted to NERC with the concurrent comment period
David F. Lemmons	Xcel Energy, Inc.	6	Negative	
Response: Please see SDT response to these comments on the other comment form. The SDT disagrees that the mapping of Planning Coordinators to subordinate entities is a significant issue. Planning Coordinators must be able to identify the entities in their footprints in order to fulfill their coordination responsibilities. This standard does not apply to Generator Owners, but this SDT has coordinated on the development of PRC-024 with that SDT. Although this has long been a subject of debate, the SDT generally believes that generators smaller than the Statement of Compliance Registry thresholds can be omitted in UFLS design assessments without significantly compromising reliability. GOs below the threshold could be registered if necessary by a regional entity for reliability according to the Compliance Registry Criteria.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Affirmative	
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Affirmative	
Harold Taylor, II	Georgia Transmission Corporation	1	Affirmative	
Richard J. Mandes	Alabama Power Company	3	Affirmative	1. The lower VSL for R11 is incorrect. It assigns a lower violation for meeting the requirement. This lower VSL should be deleted. 2. In the 2nd paragraph of the high VSL for R11, change "shall conduct and document" to "conducted and documented". 3. In the last paragraph of the severe VSL for R11, change "shall conduct and document" to "conducted and documented".
Anthony L Wilson	Georgia Power Company	3	Affirmative	
Gwen S Frazier	Gulf Power Company	3	Affirmative	
Don Horsley	Mississippi Power	3	Affirmative	
Horace Stephen Williamson	Southern Company Services, Inc.	1	Affirmative	
Response: Thank you for your comment. The SDT has modified the VSLs for R11 to make these corrections.				
Edward P. Cox	AEP Marketing	6	Affirmative	AEP has provided some general comments to the last posting.
Response: Thank you for your support.				

Voter	Entity	Segment	Vote	Comment
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	Applicability of the standard, as proposed, excludes inclusion of generators; however, R4 requires PCs to model generator specific information. This represents a missing link that needs to be addressed before the standard can be approved. This standard seems to be contrary to FERC's stated concern with NPCC(Oct. 2009 Washington DC meeting) to develop a standard that can support the program it was designed to enforce.....the applicability as stated in the standard and by NERC registry criteria restricts and excludes the need for GO's that may in aggregate be necessary for a reliable UFLS program, to adhere to the standard. The standard also is potentially in conflict with the work being done on the Generator Verification Standard, which proposes to have Generator Performance During Frequency and Voltage Excursions contained in PRC-024. Sufficient coordination on NERC Standards development needs to occur on a going forward basis.
Response: Thank you for your support. The draft of PRC-024-1 is applicable to Generator Owners and has the requirement for them to supply generator under and over frequency trip settings to the Planning Coordinators. Generator applicability is deferred to PRC-024 in order to avoid double jeopardy for Generator Owners. The implementation plan for PRC-006 recognizes that PRC-024 may be approved at a different time than PRC-006. The SDT has coordinated with the PRC-024 SDT so that both PRC-006 and PRC-024 are using the same under and over frequency generator tripping curves.				
Saurabh Saksena	National Grid	1	Affirmative	At present, the proposed implementation plan language describes a one year phase-in period for compliance that is intended to provide the Planning Coordinators with sufficient time to (i) develop and/or modify UFLS programs; and, (ii) to establish an implementation plan for all required equipment changes. It must be recognized that any implementation plan would probably cover a multi-year period reflecting the time required to perform the engineering, purchasing, installation, and testing phases associated with implementing new and/or modified UFLS schemes. As an example, NPCC has already implemented a Region specific UFLS Program incorporating a six year UFLS implementation plan, with year one of the plan having ended June, 2010. As such, NPCC is concerned with how the final language included in the NERC UFLS implementation plan might impact the NPCC-specific UFLS Implementation Program. NPCC will closely monitor NERC's efforts in developing its UFLS Reliability Standard so NPCC can appropriately include the continued implementation of its Region specific UFLS Program within the NPCC Regional Standard PRC-006-NPCC-1, the required Regional Entity companion standard to the NERC UFLS Standard.
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your support. The SDT believes that NPCC's six-year implementation plan will not be adversely affected by this standard or this standard's implementation plan.				
Louis S Slade	Dominion Resources, Inc.	6	Affirmative	Dominion appreciates the changes the SDT made to address our concerns.
Response: Thank you for your support.				
Tim Hattaway	PowerSouth Energy Cooperative	5	Affirmative	R10 needs further clarification. One would assume that the "element" referred to is one that is essential to the correct function of the UFLS scheme?
Response: "Automatic switching of Elements" refers to switching of, among other Elements, cap banks. The intent here is for switching necessary to avoid excessive voltage following UFLS operations. R10 has been modified to remove the confusion.				
Charles H Yeung	Southwest Power Pool	2	Affirmative	SPP votes in favor of the standard but directs the SDT to the ISO RTO Council comments submitted on the PRC-006 standards. We are concerned the generator owner/operators are not included as applicabile registered entities to this standard but understand there is a separate effort to develop generator owner/operator standards that could require them to provide UFLS data to Planning Coordinators. Absent that enforceable requirement, PCs could be subject to inappropriate violations if a GO fails to provide needed UFLS data. In order to move new standards forward that rely on other yet to be approved standards, NERC must take a sensible approach in enforcement of requirements if a violation is found to be caused by gaps in enforceable standards as mentioned.
Response: Thank you for your support. There is a requirement in the draft PRC-024-1 for Generator Owners to supply Planning Coordinators and other entities generating unit over and under frequency trip settings. The SDT recognizes that PRC-024 may be approved at a different time and has inserted a provision in the implementation plan document to account for that possibility. Generator applicability is deferred to PRC-024 to avoid double jeopardy. The number of non-conforming generators is expected to be small and should not cause a compliance issue for Planning Coordinators in an interim period, if any, before Generator Owner data becomes available to them. Generator tripping curves common to PRC-006-1 and PRC-024-1 (Attachment 1) have been chosen based on the off-nominal frequency duration recommendations of major generator manufacturers and were also chosen in recognition of legacy region guidelines on generator tripping.				
Kenneth D. Brown	Public Service Electric and Gas Co.	1	Affirmative	The PSEG Companies are voting affirmative on this standard with the following understanding of the intent of these Standards. PSEG believes

Voter	Entity	Segment	Vote	Comment
Jeffrey Mueller	Public Service Electric and Gas Co.	3	Affirmative	that the Standard Drafting Team has appropriately charged the Planning Coordinators with the responsibility for development and coordination of UFLS programs and assessments. The PCs are best positioned to carry out these responsibilities as part of their planning activities. In many areas such as ISOs and RTOs the individual TOs and DPs do not have the regional view that is necessary to successfully design, coordinate and assess UFLS programs. TOs and DPs role would be primarily to provide data such as forecast peak load and installed UFLS capability upon request of the PCs, and to install and maintain the TO/DP's share of UFLS capability as determined by the PC. PSE&G will support the Planning Coordinators with system information and compliance data as required to meet their needs.
Response: Thank you for your support.				
Steven Grego	MEAG Power	3	Affirmative	The reference to "automatic switching of Elements" needs to be clarified. Does it mean that the TO needs to switch capacitor banks, or does it refer to the breakers equipped with UF relays? If it is referring to capacitor banks, is this applicable near major generation busses?
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Affirmative	
Response: Yes, "automatic switching of Elements" refers to switching of, among other Elements, cap banks. R10 has been modified to remove the confusion. Cap bank switching may be particularly applicable near generation if excessive V/Hz is observed following UFLS operations.				
Silvia P Mitchell	Florida Power & Light Co.	6	Affirmative	This revised definition is better written.
Response: Thank you for your support.				
Bruce Merrill	Lincoln Electric System	3	Abstain	LES appreciates the Drafting Team's addition of R14 to allow for stakeholder input into the development of the PC's UFLS program. However, LES believes that the stakeholder process could be better defined to reflect a more formalized process similar to that of the NERC standards development process.
Eric Ruskamp	Lincoln Electric System	6	Abstain	
Response: This standard does not preclude development of regional standards in a process that may involve all interested entities in the region.				
Jeff Nelson	Springfield Utility Board	3	Abstain	SUB provided some responses on the Comment Form.
Response: Please see SDT responses to comments on the comment form.				

Justification for the proposed WECC Interconnection-Wide Variance to PRC-006-1

Background

In the aftermath of system-wide disturbances occurring within the Western Interconnection on July 2 and 3 and August 10, 1996, President Clinton appointed a "Blue Ribbon" panel to perform a comprehensive assessment of these disturbances and make recommendations to enhance reliability within the Western Interconnection. The investigations culminated in two reports: the "WSCC Disturbance Report for the Power System Outages that Occurred on the Western Interconnection on July 2, 1996 and July 3, 1996," and "WSCC Disturbance Report for the Power System Outage that Occurred on the Western Interconnection on August 10, 1996" (Disturbance Reports). The Disturbance Reports' recommendations identified several reliability issues for further investigation. One of these issues was the efficacy of existing policies and procedures related to off-nominal frequency (underfrequency load shedding (UFLS) programs), the purposes of which are to arrest potential system collapses due to large frequency deviations, minimize associated adverse impacts caused by cascading outages, and aid in quickly restoring the system to normal operations.

Status

The Western Electricity Coordinating Council (WECC) Planning Coordination Committee (PCC) and the Operating Committee (OC) developed a coordinated off-nominal frequency load shedding and restoration plan for the Western Interconnection in the fall of 1997 (1997 Coordinated Plan). The WECC Board of Trustees approved the 1997 Coordinated Plan on December 4, 1997.

In 2009, the WECC PCC and OC formed a task force to review the effectiveness of the existing protection relays associated with the 1997 Coordinated Plan. The results indicated that WECC members' relay settings conform to the 1997 Coordinated Plan performance requirements, both in arresting frequency decline before frequency reaches 58.0 Hz and in recovering frequency to 59.5 Hz or higher. These results also indicated that UFLS relays will not activate until there has been a cascading disturbance across multiple entities' systems. In addition, none of the Western Interconnection's sub-areas will experience an off-nominal frequency event due to either single or dual most severe contingency losses of generation resources if the losses occur within known island configurations.

The members of the WECC recognize the need for a common plan for underfrequency load shedding. The members of the WECC have agreed to follow and operate their systems in accordance with the Coordinated Plan as an essential element of a well-planned and operated Western Interconnection electric system.

WECC believes it is necessary to maintain the reliability benefits of the WECC Coordinated Plan as NERC moves forward with the revision to PRC-006. The language in the proposed variance is intended to ensure that the Planning Coordinators in the Western Interconnection continue to implement the WECC Coordinated Plan rather than developing new UFLS Plans that are not fully coordinated with the WECC Coordinated Plan. The variance language requires this coordination, while still requiring the individual Planning Coordinators to meet the system performance levels identified in the NERC Continent-wide Reliability Standard.

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Justification for the proposed Quebec Interconnection-Wide Variance to PRC-006-1

Hydro-Quebec Variance

Earlier in 2009, NPCC identified the need for a variance to the standard for the Québec Interconnection within NPCC. Due to the physical characteristics of the Québec system the UFLS program in Québec arrests frequency at a lower threshold and permits higher frequency overshoot than allowed in the proposed standard. The installed generation in the Québec Interconnection is 98 percent hydraulic generation, allowing wider tolerances on frequency performance without jeopardizing reliability. The variance also establishes a different capacity threshold for the generating units for which underfrequency and overfrequency trip settings must be modeled to address concerns that by 2020, 10 percent of the installed capacity in Québec may be located at plants less than 75 MVA. The Standards Committee appointed a member from the Québec Interconnection to the drafting team to develop the variance for Québec. Working closely with this representative, the team developed the variance to Requirement R3 parts 3.1 and 3.2 and Requirement R4 parts 4.1 and 4.2. The variance to these requirements reference separate under and overfrequency curves included as attachments 1A to the standard.

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Justification for Proposed VRFs and VSLs for PRC-006-1 – Automatic Underfrequency Load Shedding

This document provides the justification for assignment of VRFs and VSLs, identifying how each proposed VRF and VSL meets NERC's criteria and FERC's Guidelines. NERC's criteria for setting VRFs and VSLs; FERC's five guidelines (G1 – G5) for approving VRFs; and FERC's four guidelines (G1-G4) for setting VSLs are provided at the end of this document.

PRC-006-1 VRF and VSL Justifications		
R1	Proposed VRF	Medium
	NERC VRF Discussion	*This requirement is assigned a medium VRF because it is a planning requirement that while is administrative in nature is an input to other requirements in the standard that are assigned a higher VRF. Documenting criteria for selecting islands is an important step in designing a UFLS program but is administrative in nature. This is requirement, if violated, would not adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system but violation of the dependent requirements could have a higher impact on the bulk electric system*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Not applicable to this requirement.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *Requirement R1 while administrative in nature is an input to requirements that have a greater impact on the bulk electric system than an administrative requirement does and as a result of the dependency Requirement R1 is assigned a Medium VRF.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *Not applicable to this requirement.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC VRF guidelines.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, that may form islands.
	Proposed High VSL	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in

PRC-006-1 VRF and VSL Justifications		
		adjacent Planning Coordinator footprints and Regional Entity footprints, that may form islands
	Proposed Severe VSL	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator footprints and Regional Entity footprints, that may form islands
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*There is currently no requirement like the requirement proposed in PRC-006-1. The VSL assignment does not lower the current level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
R2	Proposed VRF	Medium
	NERC VRF Discussion	*This requirement is assigned a medium VRF because it is a planning requirement that is more than administrative in nature because it requires each Planning Coordinator to select islands to use as a basis for designing a UFLS program. While not administrative (hence not Lower), violating this requirement would not, under emergency, abnormal, or restoration conditions anticipated by the preparations, lead to bulk electric system instability, separation, or cascading failures, nor hinder restoration to a normal condition. The result of this requirement is the list of islands to serve as a basis for UFLS program design.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Not applicable to this requirement.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *While this requirement is similar to Requirement R1 this requirement is more than administrative (greater than Lower) because islands are the basis of the UFLS program design.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *Not applicable to this requirement.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of Medium VRF.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *This requirement in part relies on the output of requirement R1, the criteria for selecting islands. While Requirement R1 is a lower VRF this requirement is a Medium because the identification of islands for establishing a UFLS program is the intent of the requirement and is more than administrative in nature.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2 or 2.3.
	Proposed High VSL	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2 or 2.3.
	Proposed Severe VSL	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2 or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.
	FERC VSL G1 Violation Severity Level Assignments Should Not	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of parts an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs*

	Have the Unintended Consequence of Lowering the Current Level of Compliance	*do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
R3	Proposed VRF	High
	NERC VRF Discussion	*This requirement is assigned a High VRF because this requirement requires each Planning Coordinator to design a UFLS program that meet specific performance characteristics. This is a requirement in a planning time frame that, if violated, could hinder restoration to a normal condition.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *This requirement does not fall into one of the categories identified.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *This requirement does have sub-parts but these parts all support the parent requirement and do not have independent objectives.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *Not applicable to this requirement.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of High*

		VRF.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	The Planning Coordinator developed an UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.
	Proposed High VSL	The Planning Coordinator developed an UFLS program including notification of and a schedule for implementation by UFLS entities within its footprint, but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.
	Proposed Severe VSL	The Planning Coordinator developed an UFLS program including notification of and a schedule for implementation by UFLS entities within its footprint, but failed to meet all the performance characteristic in parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of "Parts" of a requirement that an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance. PRC-006-0 Requirement R1 requires that the RRO develop a program. This requirement contains four sub-parts that align with separate requirements in the proposed standard. These separate requirements have their own VRF and set of VSLs for compliance. Requirement R1.1 in PRC-006-0 maps to R5, R7, and R13 in draft (3) PRC-006-1.* *Requirement R1.2 in PRC-006-0 maps to R3 in draft (3) PRC-006-1* *Requirement R1.3 in PRC-006-0 maps to R6, R7, and R8 in draft (3) PRC-006-1.* *Requirement R1.4 in PRC-006-0 maps to R4, and R11.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*

	Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
R4	Proposed VRF	High
	NERC VRF Discussion	*This requirement is assigned a High VRF because the reliability objective of this requirement is to perform an assessment of the UFLS program every five years. Violation of this requirement, by failing to validate the UFLS program through dynamic simulations, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Protection systems and their coordination*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *This requirement has sub-parts but these parts all support the parent requirement and do not have independent objectives.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *Not applicable to this requirement.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of High VRF.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF.*
	Proposed Lower VSL	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.
	Proposed Moderate VSL	The Planning Coordinator conducted and documented a UFLS assessment at

PRC-006-1 VRF and VSL Justifications		
		least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.
	Proposed High VSL	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.
	Proposed Severe VSL	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of Parts of a Requirement that an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance. Failure to complete an assessment every five years was assigned a Level Four noncompliance in PRC-006-0, which is equivalent to a Severe VSL and is also assigned a Severe VSL in the draft (3) PRC-006-1.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*

PRC-006-1 VRF and VSL Justifications		
	Assignment Should Be Consistent with the Corresponding Requirement	
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
R5	Proposed VRF	Medium
	NERC VRF Discussion	*This requirement is assigned a Medium VRF because the reliability objective of this requirement is to reach concurrence with all other affected Planning Coordinators on assessment results when an island spans multiple footprints. This requirement is ensures coordination between Planning Coordinators knowing that islands may very possibly span multiple Planning Coordinator footprints. While not administrative in nature, violation of this requirement, by failing to reach concurrence, would not necessarily , under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition hence a Medium VRF.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Protection systems and their coordination.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *This requirement does not have sub-parts but these parts all support the parent requirement and do not have independent objectives.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *Not applicable to this requirement.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of Medium VRF.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A

	Proposed Severe VSL	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written as a pass/fail VSL and contains a Severe in compliance with guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
R6	Proposed VRF	Lower
	NERC VRF Discussion	*This requirement is assigned a Lower VRF because it requires that Planning Coordinators annually maintain a UFLS database. This requirement is clearly administrative; however, it is important that UFLS data/information is stored in a database. This requirement currently exists in PRC-006-0 Requirement R1.3. It is very unlikely that violating this planning requirement, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the*

PRC-006-1 VRF and VSL Justifications		
		electrical state of the bulk electric system, or the ability to effectively control or restore the bulk electric system.
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Not applicable.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *Not applicable – this requirement does not have sub-parts.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *PRC-006-0 (not FERC approved) contains a similar requirement, R1.3 but does not have a VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of Lower VRF*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written as a pass/fail VSL and contains a Severe in compliance with guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*

PRC-006-1 VRF and VSL Justifications		
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
R7	Proposed VRF	Lower
	NERC VRF Discussion	*This requirement is assigned a lower VRF because it is a planning requirement that is administrative in nature. This requirement requires the Planning Coordinators to share their UFLS database with other Planning Coordinators. This is administrative and, if violated, would not adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Not applicable to this requirement.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *Not applicable to this requirement.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *PRC-009-0 Requirement R2 that require entities to maintain a database is assigned a lower VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of Lower VRF.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF.*
	Proposed Lower VSL	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.
	Proposed Moderate VSL	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.
	Proposed High VSL	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.

PRC-006-1 VRF and VSL Justifications		
	Proposed Severe VSL	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
R8	Proposed VRF	Lower
	NERC VRF Discussion	*This requirement is assigned a lower VRF because it is a planning requirement that is administrative in nature. The responsible entities are required to provide data to the Planning Coordinators to maintain the*

PRC-006-1 VRF and VSL Justifications		
		database. This is administrative and, if violated, would not adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Not applicable to this requirement.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *Not applicable to this requirement.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *Consistent with PRC-007-0 R2 and R3 Lower VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of Lower VRF.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF.*
	Proposed Lower VSL	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
	Proposed Moderate VSL	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
	Proposed High VSL	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
	Proposed Severe VSL	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline*

PRC-006-1 VRF and VSL Justifications		
	Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
R9	Proposed VRF	High
	NERC VRF Discussion	*The reliability objective of this requirement is for responsible entities to provide load tripping in accordance with the UFLS program design and schedule for application. This requirement is assigned a High VRF because violation of it, by failing to provide the load tripping required by the UFLS program design, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Protection systems and their coordination.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *Not applicable to this requirement.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *PRC-007-0 Requirement R1 is assigned a Medium VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of High VRF.*

PRC-006-1 VRF and VSL Justifications		
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF.*
	Proposed Lower VSL	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
	Proposed Moderate VSL	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
	Proposed High VSL	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
	Proposed Severe VSL	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance. Requirement R1 of PRC-007 contains many requirements (in one) that our team has split out into independent requirements and therefore the comparison of VSLs is not a apples to apples comparison. The Lower VSL for Requirement R1 of PRC-007 says that the entity missed one or more of the RRO program requirements but was consistent with the amount of load shedding. Because our corresponding requirement (R10) focuses only on load shedding (the other RRO requirements map to other Requirements), adopting the load shedding part of the existing Lower for R1 of PRC-007 would not make sense because, it says that the load shedding requirement was met making it an invalid VSL for our purposes. We cannot write such a VSL. The other VSLs are consistent with the other levels (with the only exception being the Lower).PRC-007-0 R1 Moderate establishes a less than 95% of the regional requirement. PRC-007-0 R1 High establishes a less than 90% of the regional requirement and PRC-007-0 R1 Severe establishes a less than 85% of the regional requirement.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*

PRC-006-1 VRF and VSL Justifications		
	Severity Level Assignments that Contain Ambiguous Language	
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
R10	Proposed VRF	High
	NERC VRF Discussion	*The reliability objective of this requirement is that Transmission Owners provide automatic switching of Elements according to the UFLS program design. Similar to requirement R9, this requirement is assigned a High VRF because violation of it, by failing to provide automatic switching of Elements required by the UFLS program design, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system failure (blackout), or could place the bulk electric system at an unacceptable risk of failure (blackout), and could hinder restoration to a normal condition.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Protection systems and their coordination.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *Not applicable to this requirement.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *Not applicable to this requirement.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of High VRF.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF.*
	Proposed Lower VSL	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
	Proposed Moderate VSL	The Transmission Owner provided less than 95% but more than (and

PRC-006-1 VRF and VSL Justifications		
		including) 90% automatic switching of existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator footprint in which it owns transmission
	Proposed High VSL	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
	Proposed Severe VSL	The Transmission Owner provided less than 85% automatic switching of existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance. While there isn't an exact requirement in the current body of standards (this cannot be mapped to an existing requirement) a similar requirement PRC-007-0 Requirement R1 VSL's establish the same increments of load shedding as the proposed VSLs for this requirement.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
	Violations	

PRC-006-1 VRF and VSL Justifications		
R11	Proposed VRF	Medium
	NERC VRF Discussion	*A similar requirement exists in PRC-009-0 Requirement R1 and is assigned a Medium VRF. This requirement is assigned a Medium VRF because it requires assessment of UFLS equipment performance and UFLS program effectiveness during specified events involving UFLS activation that could identify deficiencies in either, and if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of the bulk electric system, or the ability to effectively control or restore the bulk electric system.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Not directly applicable to this requirement.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *Only one VRF is assigned to requirement and its sub-parts.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *Consistent with PRC-009-0 R1 VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of Medium VRF.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF.*
	Proposed Lower VSL	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.
	Proposed Moderate VSL	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.
	Proposed High VSL	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified

PRC-006-1 VRF and VSL Justifications		
		in Requirement R11, Parts 11.1 or 11.2.
	Proposed Severe VSL	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the Parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of parts an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
	Violation, Not on A Cumulative Number of Violations	

PRC-006-1 VRF and VSL Justifications		
R12	Proposed VRF	Medium
	NERC VRF Discussion	*A similar requirement exists in PRC-009-0 Requirement R1 and is assigned a Medium VRF. This requirement is assigned a Medium VRF because it requires assessment of UFLS equipment performance and UFLS program effectiveness during specified events involving UFLS activation that could identify deficiencies in either, and if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of the bulk electric system, or the ability to effectively control or restore the bulk electric system.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Not directly applicable to this requirement.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *Not applicable – this requirement does not have sub-parts.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *Consistent with PRC-009-0 R1 VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of Medium VRF.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.
	Proposed High VSL	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.
	Proposed Severe VSL	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
	FERC VSL G1 Violation Severity Level	*The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of Parts of a Requirement that an*

PRC-006-1 VRF and VSL Justifications		
	Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written not as a pass/fail VSL and guideline 2A does not apply. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
R13	Proposed VRF	Medium
	NERC VRF Discussion	*A similar requirement exists in PRC-009-0 Requirement R1 and is assigned a Medium VRF. This requirement is assigned a Medium VRF because it requires assessment of UFLS equipment performance and UFLS program effectiveness during specified events involving UFLS activation that could identify deficiencies in either, and if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of the bulk electric system, or the ability to effectively control or restore the bulk electric system.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Not directly applicable to this requirement.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *Not applicable – this requirement does not have sub-parts.*

PRC-006-1 VRF and VSL Justifications		
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *Consistent with PRC-009-0 R1 VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of Medium VRF.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	*The VSL is written as a pass/fail VSL and contains a Severe in compliance with guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4	*The VSL is based on a single violation of the requirement.*

PRC-006-1 VRF and VSL Justifications		
	Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

PRC-006-1 VRF and VSL Justifications		
R14	Proposed VRF	Lower
	NERC VRF Discussion	*A similar requirement exists in FAC-010-2 Requirement R5 and is assigned a Lower VRF. This requirement is assigned a Lower VRF because it is administrative in nature and if violated would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report • *Not directly applicable to this requirement.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard • *Not applicable – this requirement does not have parts and similar requirements elsewhere in the standard.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards • *Consistent with FAC-010-2 R5 VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs • *The assignment is consistent with the NERC definition of Lower VRF.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation • *There is only one objective in this requirement and it is assigned an appropriate VRF.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSLs for the stated requirement are not based on numeric gradations. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.*
	FERC VSL G2 Violation Severity Level Assignments Should Ensure	*The VSL is written as a pass/fail VSL and contains a Severe in compliance with guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.*

	Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	*The VSL aligns with the language of the requirement, and does not add to nor take away from it.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL is based on a single violation of the requirement.*

NERC's VRF Criteria:

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or

restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC's VRF Guidelines:

VRF G1 – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. From footnote 15 of the May 18, 2007 Order, FERC's list of critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System includes:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

VRF G2 – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

VRF G3 – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

VRF G4 – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

VRF G5 –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC's Criteria for VSLs:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC's VSL Guidelines:

VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance (Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.)

VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties (A violation of a "binary" type requirement must be a "Severe" VSL. Avoid using ambiguous terms such as "minor" and "significant" to describe noncompliant performance.)

VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement (VSLs should not expand on what is required in the requirement.)

VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations (. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.)

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Implementation Plan for Underfrequency Load Shedding Project

Standards Involved

- PRC-006-1 Underfrequency Load Shedding
- EOP-003-2 – Load Shedding Plans
- PRC-006-0 — Development and Documentation of Regional UFLS Programs
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements
- PRC-009-0 — UFLS Performance Following an Underfrequency Event

Prerequisite Approvals

With one exception, there are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Under Frequency Load Shedding standard and any associated regional reliability standards can be implemented. Parts 4.1 through 4.6 of Requirement R4 of the Under Frequency Load Shedding standard shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

Proposed Effective Date

Compliance with the new version PRC-006-1 — Underfrequency Load Shedding reliability standard (Requirements R1 through R14 with the exception noted above for Requirement R4, Parts 4.1 through 4.6) is effective one year following the first day of the first calendar quarter after applicable regulatory approvals.

The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time: 1) to develop, modify, or validate (to determine that the program meets performance characteristics) existing UFLS programs, and 2) to establish a schedule for implementation, or validate a schedule for completion of program revisions already in progress. Transmission Owners and Distribution Providers shall comply with the schedule determined by the Planning Coordinator but no sooner than the effective date of the standard.

Compliance with the revised EOP-003-2 — Load Shedding Plans reliability standard is effective one year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

Applicability

Certain requirements within the proposed standard are intended to apply only to entities that own or operate UFLS relays. These requirements would not apply to other entities. The drafting team has designated these entities that own or operate UFLS relays as “UFLS Entities.” They may include the following:

- Transmission Owners
- Distribution Providers

For decades underfrequency load shedding programs have been implemented by different entities depending on how the transmission system was constructed and owned. In some parts of the country, Distribution Providers accomplished this task, in others it was the Transmission Owners. Indeed, the set of standards intended to be replaced by this new standard allowed either of these registered entities, along with others in some cases, to accomplish the task of owning and operating UFLS relays. Because of this historical nature of the entities involved in the implementation of UFLS programs, and as listed in the applicability listed in the standards PRC-007-0 and PRC-009-0 that this standard is intended to replace, each of the functions listed above will have a role in implementing UFLS programs.

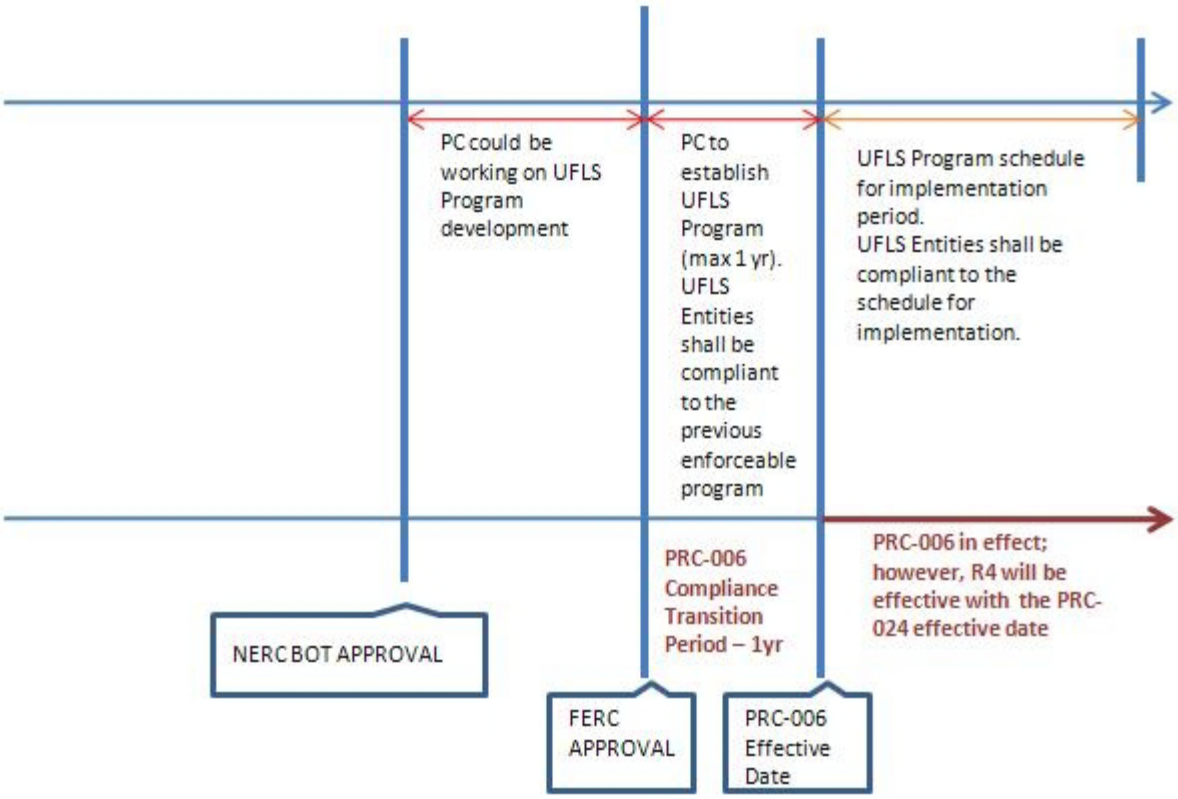
Retired Standards

The following standards will be retired when PRC-006-1 becomes effective:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-009-0 — UFLS Performance Following an Underfrequency Event will be completely retired once PRC-006-1 becomes effective as specified above.

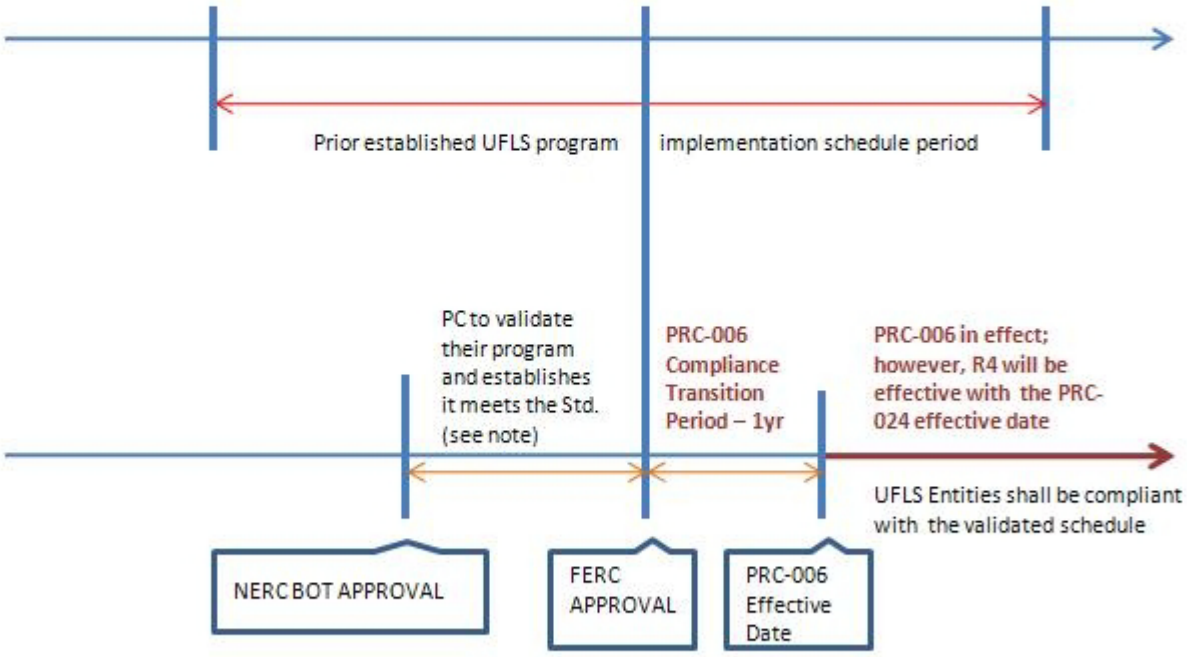
UFLS Timeline Example 1

(No Existing program)



UFLS Timeline Example 2

(Existing UFLS program)



Note: If the PC determines that their program is not valid to the standard, PC will need to follow Timeline Example 1.

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Implementation Plan for Under ~~F~~frequency Load Shedding ~~Reliability Standard~~ Project

Standards Involved

- PRC-006-1 Underfrequency Load Shedding
- EOP-003-2 – Load Shedding Plans
- PRC-006-0 — Development and Documentation of Regional UFLS Programs
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements
- PRC-009-0 — UFLS Performance Following an Underfrequency Event

Prerequisite Approvals

With one exception, there are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Under Frequency Load Shedding standard and any associated regional reliability standards can be implemented. Parts 4.1 through 4.6 of Requirement R4 of the Under Frequency Load Shedding standard shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

Proposed Effective Date

Compliance with the new version PRC-006-1 — Underfrequency Load Shedding reliability standard (Requirements R1 through R14 with the exception noted above for Requirement R4, Parts 4.1 through 4.6) is effective one year following the first day of the first calendar quarter after applicable regulatory approvals.

The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time: 1) to develop, modify, or validate (to determine that the program meets performance characteristics) existing UFLS programs, and 2) to establish a schedule for implementation, or validate a schedule for completion of ~~-~~program revisions already in progress. Transmission Owners and Distribution Providers shall comply with the schedule determined by the Planning Coordinator but no sooner than the effective date of the standard.

Compliance with the revised EOP-003-~~1~~ 2 — Load Shedding Plans reliability standard is effective one year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

Applicability

Certain requirements within the proposed standard are intended to apply only to entities that own or operate UFLS relays. These requirements would not apply to other entities. The drafting team has designated these entities that own or operate UFLS relays as “UFLS Entities.” They may include the following:

- Transmission Owners
- Distribution Providers

For decades underfrequency load shedding programs have been implemented by different entities depending on how the transmission system was constructed and owned. In some parts of the country, Distribution Providers accomplished this task, in others it was the Transmission Owners. Indeed, the set of standards intended to be replaced by this new standard allowed either of these registered entities, along with others in some cases, to accomplish the task of owning and operating UFLS relays. Because of this historical nature of the entities involved in the implementation of UFLS programs, and as listed in the applicability listed in the standards PRC-007-0 and PRC-009-0 that this standard is intended to replace, each of the functions listed above will have a role in implementing UFLS programs.

Retired Standards

The following standards will be retired when PRC-006-1 becomes effective:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-009-0 — UFLS Performance Following an Underfrequency Event will be completely retired once PRC-006-1 becomes effective as specified above.

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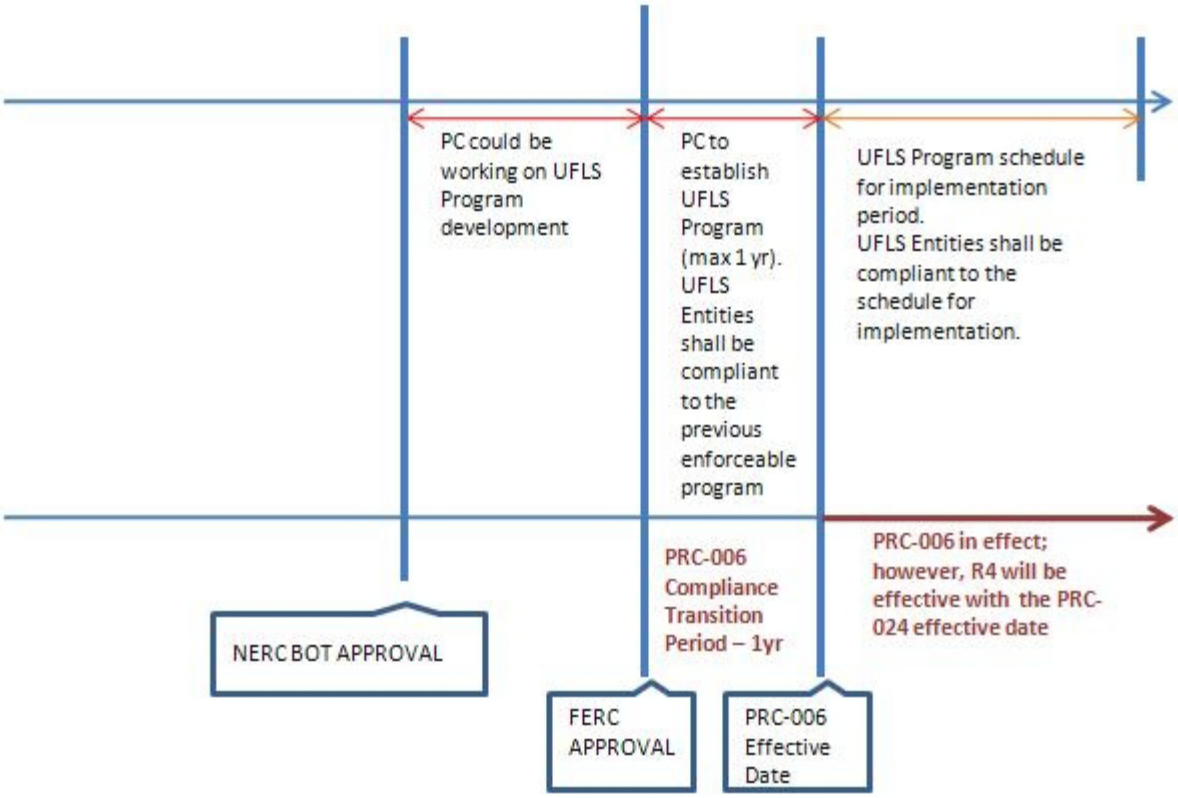
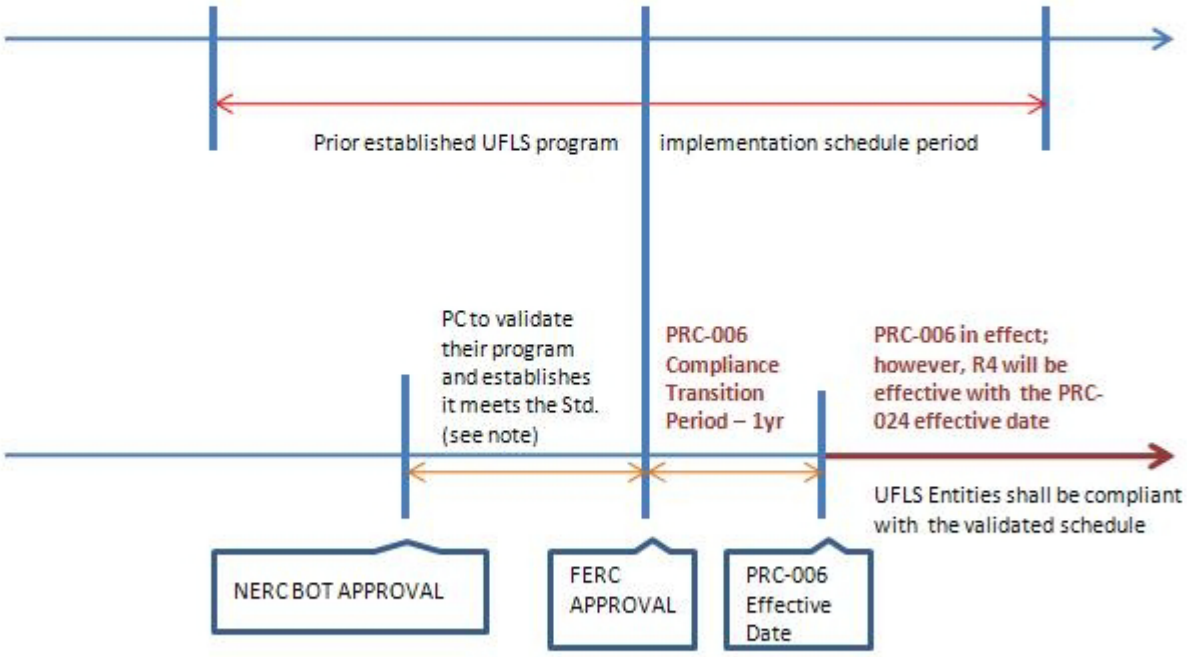
UFLS Timeline Example 1

(No Existing program)



UFLS Timeline Example 2

(Existing UFLS program)



Note: If the PC determines that their program is not valid to the standard, PC will need to follow Timeline Example 1.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Standards Committee approved the Supplemental SAR for posting on October 7, 2009 that expanded the SDT's scope to include EOP-003-1 but limiting that scope to only eliminating references to Under-frequency Load Shedding in EOP-003-1.
2. The Standards Drafting Team posted the standard for a third comment period June 11, 2010 – July 16, 2010.
3. The Standard Drafting Team conducted a pre-ballot review of the standard on June 11, 2010 – July 2, 2010
4. The Standard Drafting Team conducted an initial ballot of the standard and non-binding poll of the VRFs and VSLs on July 8, 2010 – July 17, 2010.
5. The Standard Drafting Team conducted a second ballot of the standard on July 24, 2010 – August 3, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third ballot period of the proposed standard.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Third ballot	September, 2010
2. Request BOT approval	November 3, 2010
3. File Standard with FERC	December, 2010

A. Introduction

1. Title: **Load Shedding Plans**

2. Number: EOP-003-2

3. Purpose: A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. Applicability:

4.1. Transmission Operators.

4.2. Balancing Authorities.

5. Effective Date: One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions

R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

M1. Each Transmission Operator that has or directs the deployment of undervoltage load shedding facilities, shall have and provide upon request, its automatic load shedding plans. (Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
R2	N/A	N/A	N/A	The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.
R3.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
R4.	N/A	N/A	N/A	The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.
R5.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
R7.	The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.
R8.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

E. **Regional Differences**

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Modified R4, R5, R6 and associated VSLs for R2, R4, and R7to clarify that the requirements don’t apply to automatic underfrequency load shedding	Revised to eliminate redundancies with PRC-006-1

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Standards Committee approved the Supplemental SAR for posting on October 7, 2009 that expanded the SDT's scope to include EOP-003-1 but limiting that scope to only eliminating references to Under-frequency Load Shedding in EOP-003-1.
2. The Standards Drafting Team posted the standard for a third comment period June 11, 2010 – July 16, 2010.
3. The Standard Drafting Team conducted a pre-ballot review of the standard on June 11, 2010 – July 2, 2010
4. The Standard Drafting Team conducted an initial ballot of the standard and non-binding poll of the VRFs and VSLs on July 8, 2010 – July 17, 2010.
5. The Standard Drafting Team conducted a second ballot of the standard on July 24, 2010 – August 3, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third ballot period of the proposed standard.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Third ballot	September, 2010
2. Request BOT approval	November 3, 2010
3. File Standard with FERC	December, 2010

A. Introduction

1. **Title:** **Load Shedding Plans**

2. **Number:** EOP-003-21

3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date:** One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions

R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

M1. Each Transmission Operator that has or directs the deployment of undervoltage load shedding facilities, shall have and provide upon request, its automatic load shedding plans. (Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring ~~Period and Reset Timeframe~~

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
R2	N/A	N/A	N/A	The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.
R3.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
R4.	N/A	N/A	N/A	The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.
R5.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
R7.	The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.
R8.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

E. **Regional Differences**

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
12	TBD	Modified R4, R5, R6 and associated VSLs for R2, R4, and R7to clarify that the requirements don't apply to automatic underfrequency load shedding	Revised to eliminate redundancies with PRC-006-1

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on November 21, 2006.
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting Team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard, and posts for comments on April 15, 2009.
10. Standards Committee approved the Supplemental SAR for posting on October 7, 2009 that expanded the SDT's scope to include EOP-003-1 but limiting that scope to only eliminating references to Under-frequency Load Shedding in EOP-003-1.
11. The Standards Drafting Team posted the standard for a third comment period June 11, 2010 – July 16, 2010.
12. The Standard Drafting Team conducted a pre-ballot review of the standard on June 11, 2010 – July 2, 2010
13. The Standard Drafting Team conducted an initial ballot of the standard and non-binding poll of the VRFs and VSLs on July 8, 2010 – July 17, 2010.
14. The Standard Drafting Team conducted a second ballot of the standard on July 24, 2010 – August 3, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third ballot period of the proposed standard.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Third ballot	September, 2010
2. Request BOT approval	November 3, 2010
3. File Standard with FERC	December, 2010

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-1

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.3 Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **(Proposed) Effective Date:**

   5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.

   5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

B. Requirements

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from regional boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

R3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: Medium][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection

within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with

those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per

Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking

- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area.
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	transmission	transmission	transmission	transmission
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.

E. Regional Variances

E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E.A.3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

EA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

EA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

EA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

E.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

E.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.E.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

M.E.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
EA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
EA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3

E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

E.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2.1. Those islands selected by applying the criteria in Requirement E.B.1, and

E.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

EB.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

E.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

E.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

E.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

E.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

E.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

E.B.11.1. The performance of the UFLS equipment,

E.B.11.2 The effectiveness of the UFLS program

E.B.12. Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.E.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.

M.E.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.

M.E.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.

M.E.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.

M.E.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.

M.E.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands
E.B.2	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include two (2) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				regional review to serve as a basis for designing its UFLS program.
E.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
E.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment at least once every five years with the other Planning Coordinators in the WECC Regional Entity area that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment at least once every five years with the other Planning Coordinators in the WECC Regional Entity area that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment at least once every five years with the other Planning Coordinators in the WECC Regional Entity area that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment at least once every five years with the other Planning Coordinators in the WECC Regional Entity area that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	through E.B.4.7.	through E.B.4.7.	through E.B.4.7.	through E.B.4.7. OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment at least once every five years with the other Planning Coordinators in the WECC Regional Entity area that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2
E.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.	assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.
E.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

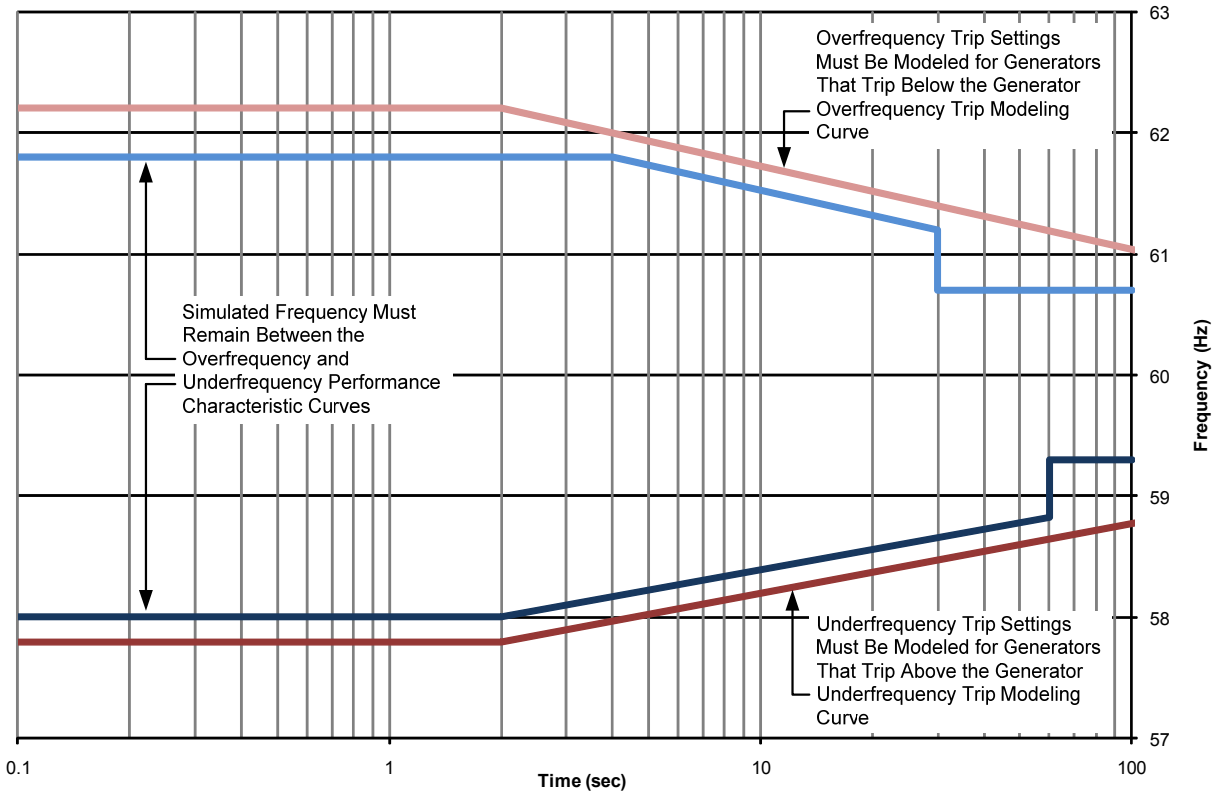
Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0	

PRC-006-1 – Attachment 1

Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6

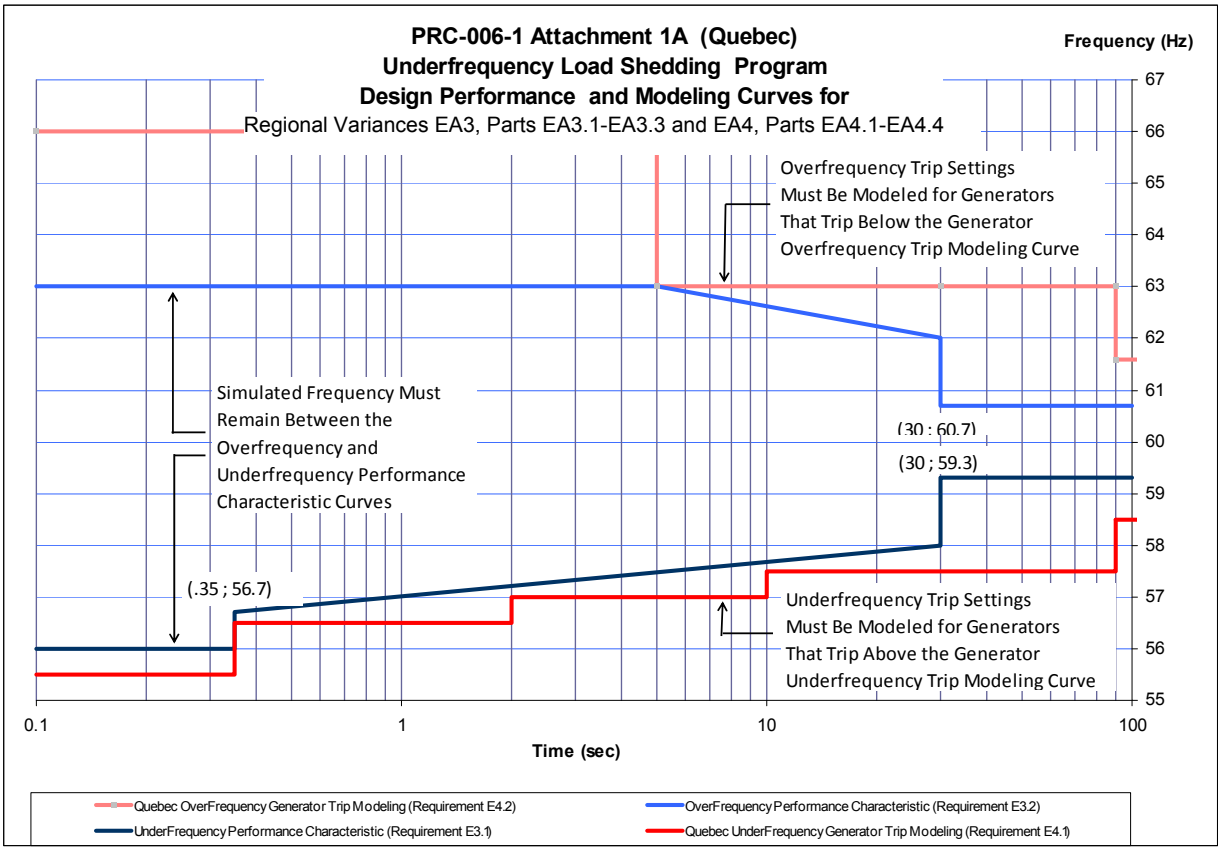


- Generator Overfrequency Trip Modeling (Requirement R4 Parts 4.4-4.6)
- Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
- Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
- Generator Underfrequency Trip Modeling (Requirement R4 Parts 4.1-4.3)

Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling		Underfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-1 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances EA3, Parts EA3.1-EA3.3 and EA4, Parts EA4.1-EA4.4
Frequency (Hz)
67
66
65
64
63
62
61
60
59
58
57
56
55
Overfrequency Trip Settings
Must Be Modeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(30 ; 60.7)
(30 ; 59.3)
(.35 ; 56.7)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip Modeling Curve
0.1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement E4.2)
OverFrequency Performance Characteristic (Requirement E3.2)
UnderFrequency Performance Characteristic (Requirement E3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement E4.1)

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on November 21, 2006.
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting Team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard, and posts for comments on April 15, 2009.
10. Standards Committee approved the Supplemental SAR for posting on October 7, 2009 that expanded the SDT's scope to include EOP-003-1 but limiting that scope to only eliminating references to Under-frequency Load Shedding in EOP-003-1.
11. The Standards Drafting Team posted the standard for a third comment period June 11, 2010 – July 16, 2010.
12. The Standard Drafting Team conducted a pre-ballot review of the standard on June 11, 2010 – July 2, 2010
13. The Standard Drafting Team conducted an initial ballot of the standard and non-binding poll of the VRFs and VSLs on July 8, 2010 – July 17, 2010.
14. The Standard Drafting Team conducted a second ballot of the standard on July 24, 2010 – August 3, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third ballot period of the proposed standard.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Third ballot	September, 2010
2. Request BOT approval	November 3, 2010
3. File Standard with FERC	December, 2010

A. Introduction

1. Title: **Automatic Underfrequency Load Shedding**

2. Number: PRC-006-1

3. Purpose: To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. Applicability:

4.1. Planning Coordinators

4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

4.2.1 Transmission Owners

4.2.2 Distribution Providers

4.3 Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. (Proposed) Effective Date:

5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.

5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

B. Requirements

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from regional boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

R3. Each Planning Coordinator shall develop ~~and make available to UFLS entities~~ a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1~~2~~, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1~~2~~.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1~~2~~.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1~~2~~.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other ~~affected~~ Planning Coordinators whose areas or portions of whose areas are also part of ~~for each~~the same identified island ~~identified by any one Planning Coordinator that encompasses all or a portion of its Planning Coordinator area through~~ through one of the following ~~action(s)~~: *[VRF: Medium][Time Horizon: Long-term Planning]*

~~**5.1.** Conduct a UFLS design assessment for each island modeling all UFLS programs in the island~~

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and ~~I~~in the event the UFLS design assessment ~~per~~~~in Requirement R4~~5, ~~for the identified island Part 5.1~~ fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these ~~recommended~~ modifications as recommendations ~~to UFLS program(s)~~ to the other ~~affected~~ Planning Coordinator~~(s)~~ whose areas or portions of whose areas are also part of ~~that~~the same identified island and the ERO.~~, or~~

- ~~Develop Aa common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or~~
- ~~Conduct Aa joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island.~~

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][-Time Horizon: Long-term Planning]*

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding ~~in accordance~~if required by ~~with~~ the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which ~~it~~ the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

R13. Each Planning Coordinator, in whose area ~~or portions of whose area~~ a BES islanding event occurred~~s affecting~~ that also included the area(s) or portions of area(s) of other ~~multiple~~ Planning Coordinator(s) in the same islanding event ~~areas~~ and that resulted~~ting~~ in system frequency excursions below the initializing set points of the

UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with ~~the~~ all other ~~affected~~ Planning Coordinators whose areas ~~were also~~ or portions of whose areas were also included in the same islanding event ~~affected by the same event~~ ~~on the event assessment~~ through one of the following ~~action(s)~~: *[VRF: Medium][Time Horizon: Operations Assessment]*

~~**13.1.** Conduct a UFLS event assessment for each island modeling all UFLS programs in the island~~

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent ~~In the event~~If ~~the UFLS~~ event assessment ~~in~~per Requirement R11~~3,~~ ~~Part 13.1~~ and where the assessment fails to ~~coordinate~~ reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinator~~(s)~~ whose areas or portions of whose areas were ~~affected~~ included in the same islanding ~~by the same~~ event, ~~each Planning Coordinator shall~~ identify differences in the assessments that likely resulted in the differences in the ~~event assessment results~~conclusions and recommendations and report these differences to the other ~~affected~~ Planning Coordinators whose areas ~~were~~ or portions of whose areas were included in the same islanding event ~~affected by the event~~ and the ERO.~~, or~~
- ~~Conduct A~~a joint event assessment per Requirement R11 among the Planning Coordinators whose areas were or portions of whose areas were included in the same islanding event~~affected by the event.~~

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2 Parts 2.1 through 2.3.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3 Parts 3.1 through 3.3.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4 Parts 4.1 through 4.7.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which ~~spans~~includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as ~~letters that include recommendations,~~ joint UFLS program design documents, reports describing a joint UFLS design assessment, ~~dynamic simulation models and results,~~ letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island ~~its UFLS design assessment; including, if necessary to meet the performance characteristics in Requirement R3, modifications to the UFLS program(s) and supporting documentation such as memorandums, letters, or other dated documentation that it notified the other affected Planning Coordinators and the ERO of any necessary design changes, for any islands identified by a Planning Coordinator that encompass all or a portion of its Planning Coordinator area~~ per Requirement R5.

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it ~~annually~~ maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding ~~in accordance with~~if required by the UFLS program and schedule for application per Requirement R10.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

M13. Each Planning Coordinator, in whose area ~~or portions of whose area~~ a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as ~~letters describing likely reasons for differences in conclusions and recommendations,~~ a joint assessment report~~s~~, ~~dynamic simulation models and results,~~ independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it~~s~~ coordinated its event assessment (per R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event ~~UFLS event assessment; including, if necessary supporting dated documentation such as memorandums, letters and other dated documentation identifying differences in event assessments between Planning Coordinators, to demonstrate that event assessments of multiple Planning Coordinators in an affected island are coordinated or to show the reasons why the assessment results are different~~ per Requirement R13.

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13~~, R14~~ and Measures M11, and M13~~, and M14~~ for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas~~,~~ that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, ~~-~~that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the P~~p~~arts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the ~~p~~Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the ~~p~~Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area.
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determineds through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determinesd through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determinesd through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determinesd through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which ~~spans~~includes multiple Planning Coordinator areas or portions of those areas, failed to ~~conduct and document a UFLS assessment~~coordinate its UFLS program design through one of the manners described in Requirement R5. ~~for any island identified by any one Planning Coordinator that encompasses all or a portion of its Planning Coordinator area.~~ ~~OR~~ ~~The Planning Coordinator failed to notify all other affected Planning Coordinators and the ERO of UFLS design changes necessary to meet the performance characteristics in Requirement R3 for any island identified by any one Planning Coordinator that encompasses all or a portion of its Planning Coordinator area.~~
R6	N/A	N/A	N/A	The Planning Coordinator failed to ~~annually~~ maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	application determined by the Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of ~~Elements~~ its existing capacitor banks, Transmission Lines, and reactors to control over-voltage ~~in accordance with~~ if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner~~it~~ owns transmission	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage ~~Elements in accordance~~ if required by ~~with~~ the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner~~it~~ owns transmission	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage ~~Elements~~ if required by ~~in accordance with~~ the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner~~it~~ owns transmission	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage ~~Elements~~ if required by ~~in accordance with~~ the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner~~it~~ owns transmission
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation. ~~The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program,~~	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than ~~one year~~13 months but less than or equal to ~~13~~ 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than ~~13~~ 14 months but less than or equal to ~~14~~ 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than ~~14~~15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~conducted and documented an assessment of the event within one year of event actuation.~~		excursions below the initializing set points of the UFLS program, ~~shall~~ conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the P~~p~~arts as specified in Requirement R11, Parts11.1 or 11.2.	points of the UFLS program, failed to conduct and document an assessment of the event and evaluate~~d~~ the P~~p~~arts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, ~~shall~~ conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the P~~p~~arts as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area ~~or portions of whose area~~ a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program~~a BES islanding event affecting multiple Planning Coordinator areas and resulting in system frequency excursions below the initializing set points of the UFLS program~~, failed to ~~conduct and document~~coordinate its~~a~~ UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13.~~.~~ ~~OR~~ ~~The Planning Coordinator, in whose area a BES islanding event affecting multiple Planning Coordinator areas and resulting in system frequency excursions below the initializing set points of the UFLS program, failed to notify all other affected Planning Coordinators and the ERO of differences between UFLS event assessment and reasons for those~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~differences.~~
R14	N/A~~The Planning Coordinator did not respond to all the written comments but to more than 90% of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.~~	N/A~~The Planning Coordinator responded to 90% or less but more than 80% of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.~~	N/A~~The Planning Coordinator responded to 80% or less but more than 70% of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.~~	The Planning Coordinator ~~responded to 70% or less of the written comments submitted by UFLS entities within its Planning Coordinator area following a comment period and before finalizing its UFLS program.~~failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.

E. Regional Variances

E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E.A.3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and~~, and~~

E.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment ~~2A~~1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and~~, and~~

E.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

EA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

EA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

EA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

E.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

E.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.E.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

M.E.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
EA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
EA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3

E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

E.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2.1. Those islands selected by applying the criteria in Requirement E.B.1, and

E.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

EB.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

E.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

E.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

E.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High] [Time Horizon: Long-term Planning]*

E.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

E.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the

event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

E.B.11.1. The performance of the UFLS equipment,

E.B.11.2 The effectiveness of the UFLS program

E.B.12. Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.E.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.

M.E.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.

M.E.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.

M.E.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.

M.E.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.

M.E.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands
E.B.2	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include two (2) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				regional review to serve as a basis for designing its UFLS program.
E.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
E.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment at least once every five years with the other Planning Coordinators in the WECC Regional Entity area that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment at least once every five years with the other Planning Coordinators in the WECC Regional Entity area that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment at least once every five years with the other Planning Coordinators in the WECC Regional Entity area that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment at least once every five years with the other Planning Coordinators in the WECC Regional Entity area that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	through E.B.4.7.	through E.B.4.7.	through E.B.4.7.	through E.B.4.7. OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment at least once every five years with the other Planning Coordinators in the WECC Regional Entity area that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2
E.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.	assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.
E.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

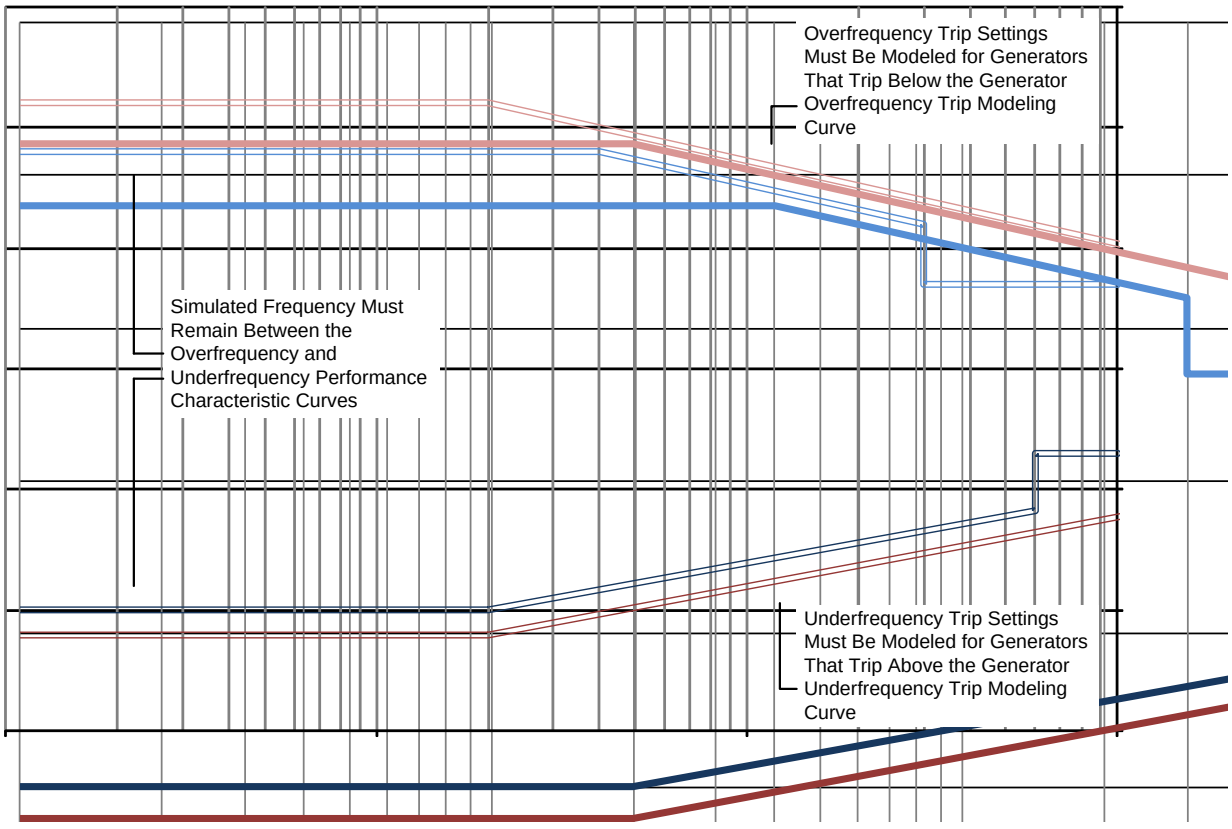
Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0	

PRC-006-1 – Attachment 1

Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



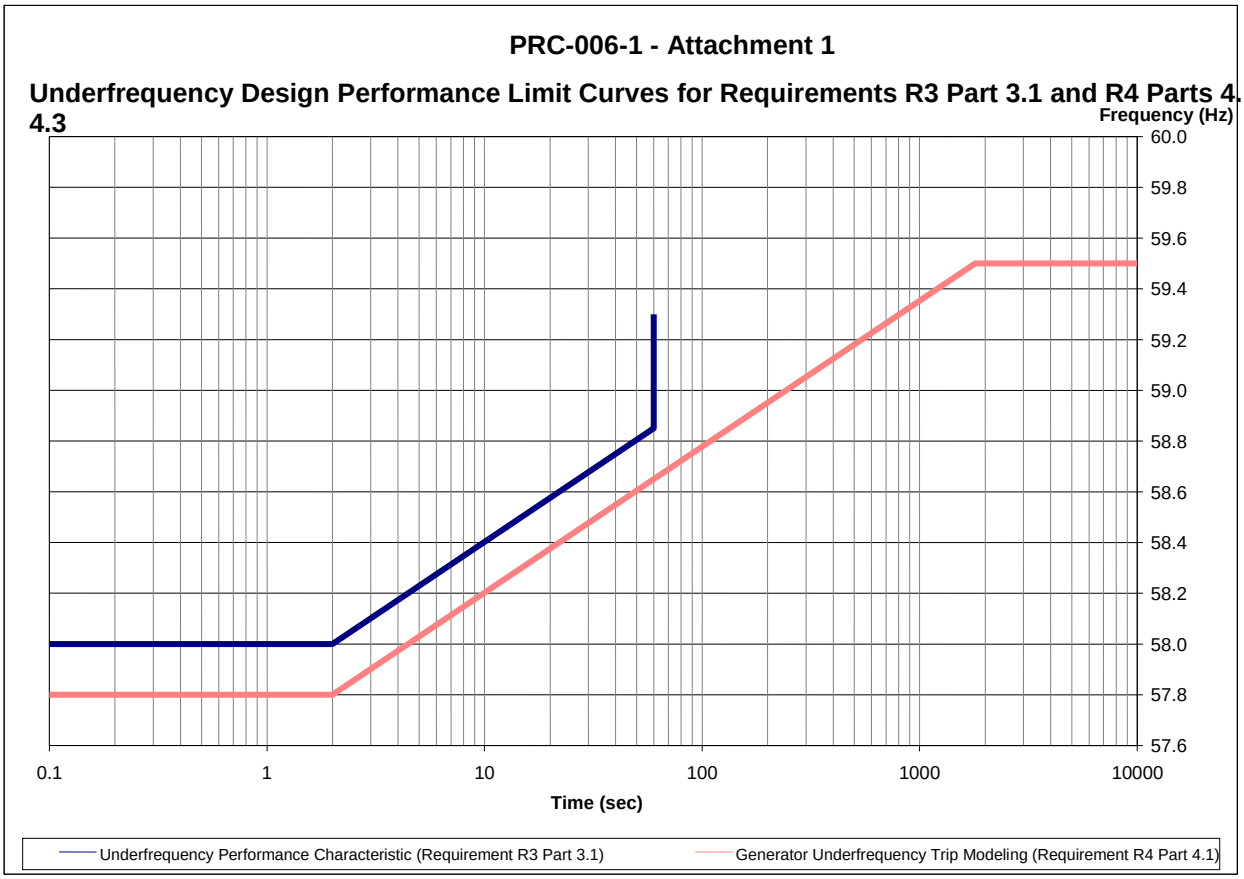
Curve Definitions

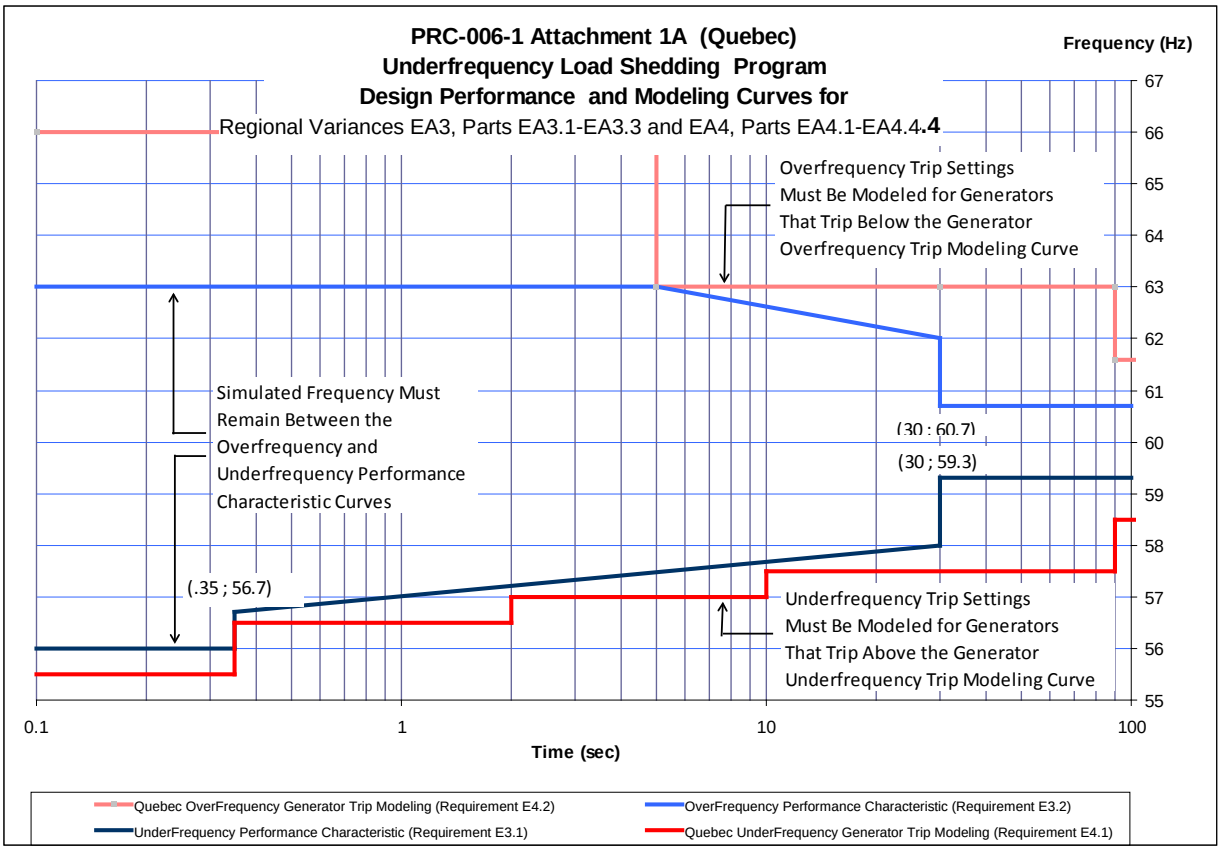
Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

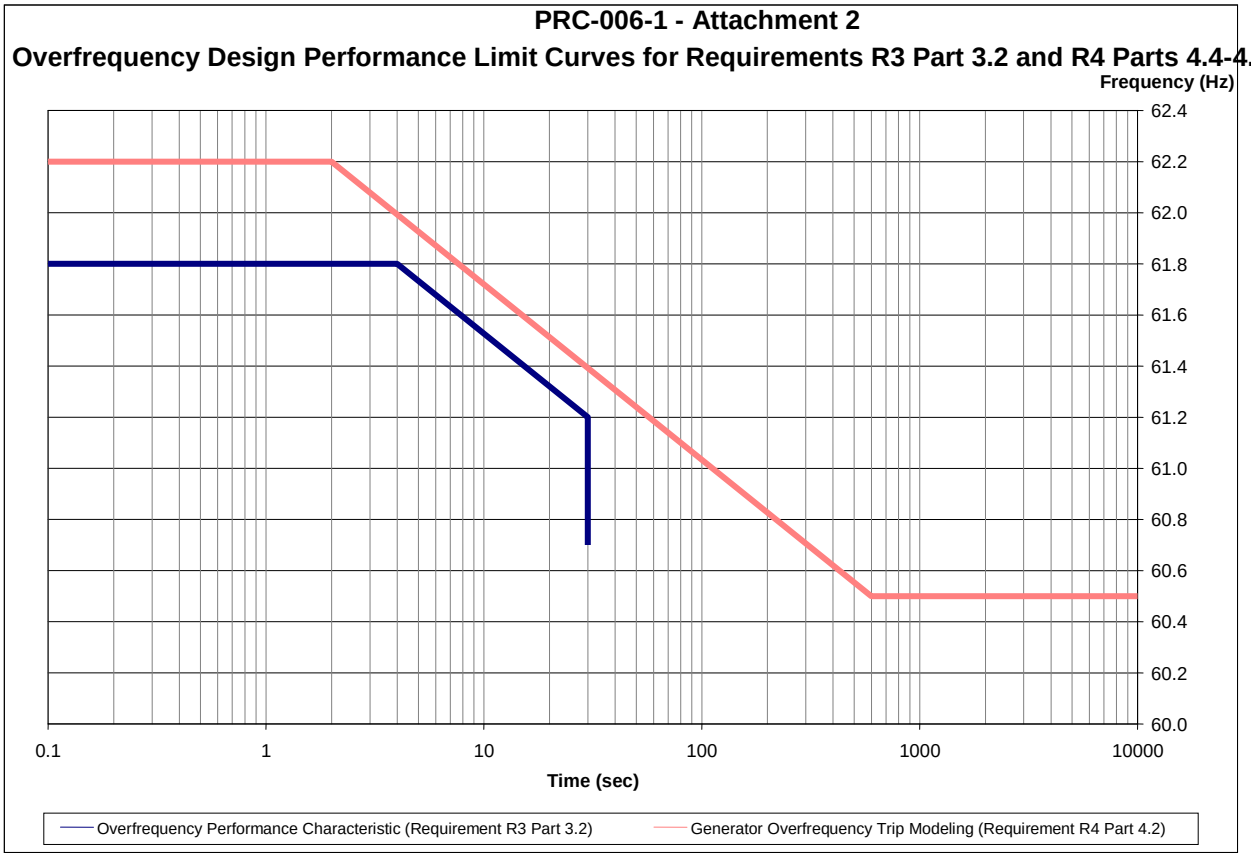
Generator Underfrequency Trip Modeling		Underfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz

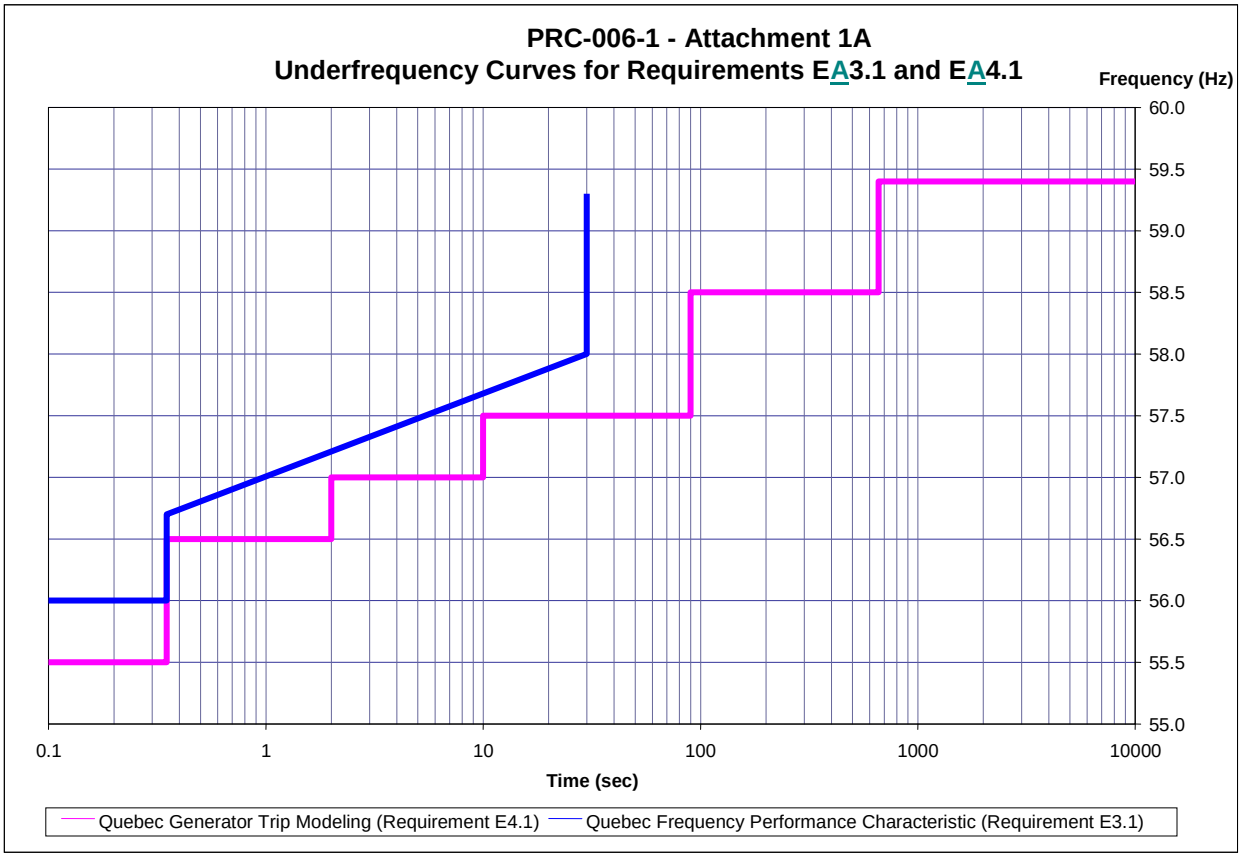
PRC-006-1 - Attachment 1

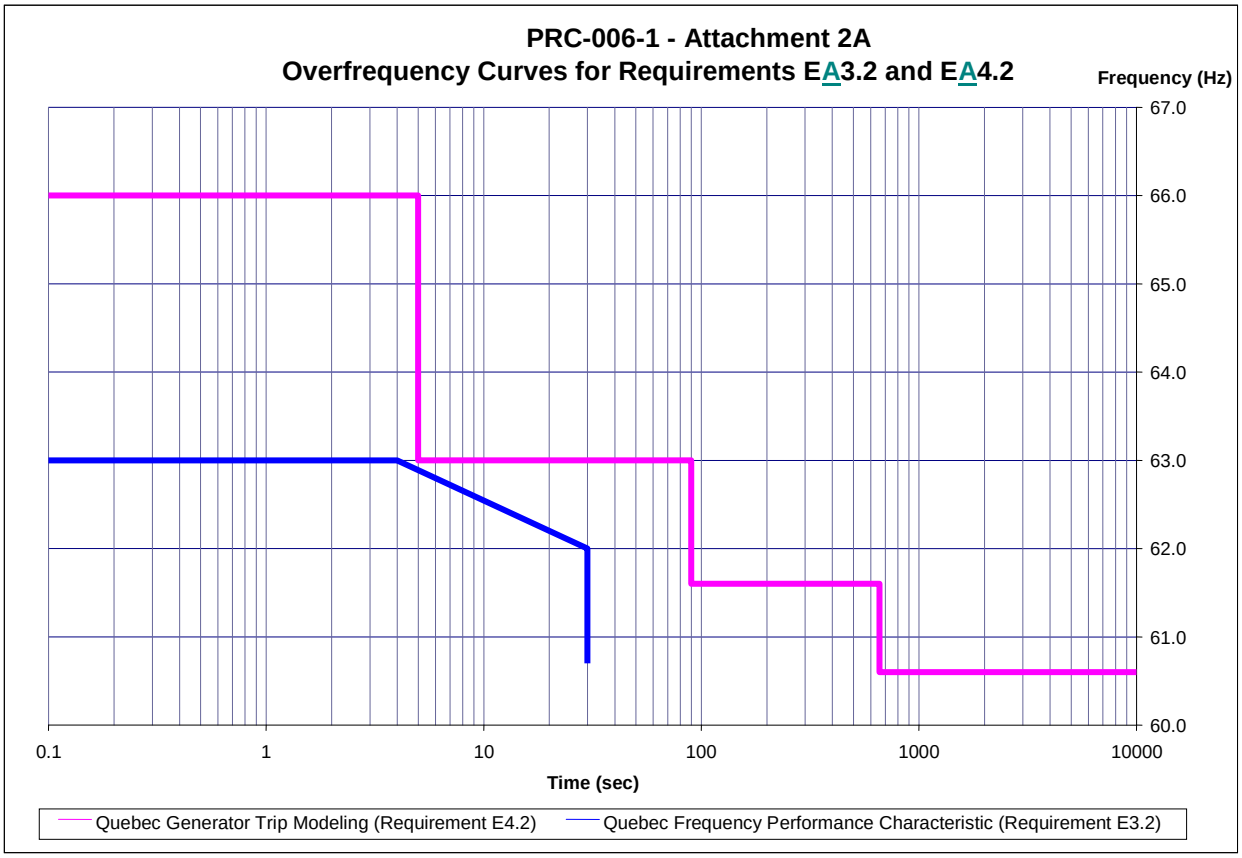
Underfrequency Design Performance Limit Curves for Requirements R3 Part 3.1 and R4 Parts 4.1 - 4.3




PRC-006-1 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances EA3, Parts EA3.1-EA3.3 and EA4, Parts EA4.1-EA4.4.4
Frequency (Hz)
Overfrequency Trip Settings
Must Be Modeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(30 ; 60.7)
(30 ; 59.3)
(.35 ; 56.7)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip Modeling Curve
67
66
65
64
63
62
61
60
59
58
57
56
55
0.1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement E4.2)
OverFrequency Performance Characteristic (Requirement E3.2)
UnderFrequency Performance Characteristic (Requirement E3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement E4.1)


PRC-006-1 - Attachment 2
Overfrequency Design Performance Limit Curves for Requirements R3 Part 3.2 and R4 Parts 4.4-4.6
Frequency (Hz)
62.4
62.2
62.0
61.8
61.6
61.4
61.2
61.0
60.8
60.6
60.4
60.2
60.0
0.1
1
10
100
1000
10000
Time (sec)
Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
Generator Overfrequency Trip Modeling (Requirement R4 Part 4.2)


PRC-006-1 - Attachment 1A
Underfrequency Curves for Requirements EA3.1 and EA4.1
Frequency (Hz)
60.0
59.5
59.0
58.5
58.0
57.5
57.0
56.5
56.0
55.5
55.0
0.1
1
10
100
1000
10000
Time (sec)
Quebec Generator Trip Modeling (Requirement E4.1)
Quebec Frequency Performance Characteristic (Requirement E3.1)


PRC-006-1 - Attachment 2A
Overfrequency Curves for Requirements EA3.2 and EA4.2
Frequency (Hz)
67.0
66.0
65.0
64.0
63.0
62.0
61.0
60.0
0.1
1
10
100
1000
10000
Time (sec)
Quebec Generator Trip Modeling (Requirement E4.2)
Quebec Frequency Performance Characteristic (Requirement E3.2)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Successive Ballot Extended

Available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2007-01 Underfrequency Load Shedding

A successive ballot for standards PRC-006-1 — Automatic Underfrequency Load Shedding and EOP-003-2— Load Shedding Plans, and the associated implementation plan, is underway and will remain open until a quorum has been achieved. Under the Standard Processes Manual, if a standard fails to achieve a quorum during the specified 10-day ballot window, the window is extended until a quorum has been achieved.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

In addition to voting on the standard, members of the ballot pool will be able to vote in a concurrent non-binding poll for the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) associated with the standard. Members who joined the ballot pool to vote on the standard were automatically entered in a separate pool to participate in the non-binding poll for the VRFs and VSLs. The non-binding poll will appear in the list of current ballots, and is labeled accordingly.

The Standards Committee encourages all members of the ballot pool to review the consideration of comments for the previous ballot and the modifications that team made to the standards. In a successive ballot, votes are not carried forward from the previous ballot. (Note that the new Standard Processes Manual requires a comment period in parallel with a successive ballot, but the Standards Committee authorized proceeding to a successive ballot without a concurrent comment period before the new manual was approved and determined to allow the drafting team to proceed without an additional comment period.)

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

Major objectives:

1. Ensure UFLS programs are developed to provide an appropriate level of reliability (not least common denominator).

2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.

3. Address the issues raised by FERC Order 693 and other applicable orders.

4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.

5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

Further details are available on the project page:
http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Successive Ballot Open
September 24 - October 3, 2010

Available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2007-01 Underfrequency Load Shedding

A successive ballot for standards PRC-006-1 — Automatic Underfrequency Load Shedding and EOP-003-1— Load Shedding Plans, and the associated implementation plan, is open through **8 p.m. Eastern on October 3, 2010**.

The Standards Committee authorized the UFLS Standard Drafting Team to conduct successive ballots in a special effort to complete this project in time to present the work to the NERC Board of Trustees for action at the November 4, 2010 meeting.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

In addition to voting on the standard, members of the ballot pool will be able to vote in a concurrent non-binding poll for the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) associated with the standard. Members who joined the ballot pool to vote on the standard were automatically entered in a separate pool to participate in the non-binding poll for the VRFs and VSLs. The non-binding poll will appear in your list of current ballots, and is labeled accordingly.

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2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.

3. Address the issues raised by FERC Order 693 and other applicable orders.
4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

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Non-binding Poll Name:	Project 2007-01: Underfrequency Load Shedding - Non-binding poll for VRF and VSLs
Poll Period:	9/24/2010 - 10/4/2010
Total # Opinions:	199
Total Ballot Pool:	315
Summary Results:	84% of those who registered to participate provided an opinion; 68% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver		
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Negative	View
1	Baltimore Gas & Electric Company	John J. Moraski	Abstain	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	CenterPoint Energy	Paul Rocha	Negative	
1	Central Maine Power Company	Brian Conroy	Abstain	
1	City of Vero Beach	Randall McCamish	Affirmative	

1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Commonwealth Edison Co.	Daniel Brotzman	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	
1	Dominion Virginia Power	John K Loftis	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Negative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Abstain	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	

1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lake Worth Utilities	Walt Gill	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	Metropolitan Water District of Southern California	Ernest Hahn	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Douglas G Peterchuck	Abstain	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Negative	View
1	PacifiCorp	Mark Sampson		
1	PECO Energy	Ronald Schloendorn	Abstain	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	

1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Negative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Abstain	
1	Puget Sound Energy, Inc.	Catherine Koch	Negative	View
1	Sacramento Municipal Utility District	Tim Kelley	Negative	View
1	Salt River Project	Robert Kondziolka	Negative	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sierra Pacific Power Co.	Rich Salgo	Negative	View
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Negative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Negative	View
1	Southwestern Power Administration	Gary W Cox	Abstain	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Keith V. Carman	Negative	
1	Tucson Electric Power Co.	John Tolo	Negative	View

1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Jason L. Murray		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Transmission Corporation	Faramarz Amjadi		
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock		
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Abstain	

3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson		
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Negative	
3	ComEd	Bruce Krawczyk	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Negative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Power Corporation	Lee Schuster	Abstain	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Abstain	
3	Gulf Power Company	Gwen S Frazier	Affirmative	

3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Los Angeles Department of Water & Power	Kenneth Silver		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	North Carolina Municipal Power Agency #1	Denise Roeder	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	OTP Wholesale Marketing	Bradley Tollerson	Negative	
3	PacifiCorp	John Apperson	Abstain	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Abstain	

3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	View
3	Salt River Project	John T. Underhill	Negative	View
3	San Diego Gas & Electric	Scott Peterson	Negative	View
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	South Mississippi Electric Power Association	Gary Hutson		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Springfield Utility Board	Jeff Nelson	Abstain	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power - Ohio	Kevin Koloini	Negative	
4	American Public Power Association	Allen Mosher	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities	Timothy Beyrle	Affirmative	

	Commission			
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Terri Pyle	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	View
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
4	Y-W Electric Association, Inc.	James A Ziebarth		
5	AEP Service Corp.	Brock Ondayko	Affirmative	

5	Amerenue	Sam Dwyer	Abstain	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Negative	View
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Tallahassee	Alan Gale	Abstain	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Robert Smith		
5	East Kentucky Power Coop.	Stephen Ricker	Negative	
5	Entergy Corporation	Stanley M Jaskot		
5	Exelon Nuclear	Michael Korchynsky	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Abstain	
5	Green Country Energy	Greg Froehling		
5	JEA	Donald Gilbert	Abstain	

5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	Mark Aikens		
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Negative	
5	Otter Tail Power Company	Stacie Hebert	Abstain	
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Mark A Heimbach		
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Power LLC	David Murray	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	RRI Energy	Thomas J. Bradish	Negative	View
5	Sacramento Municipal Utility District	Bethany Wright	Negative	View
5	Salt River Project	Glen Reeves	Negative	View
5	Seattle City Light	Michael J. Haynes	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	

5	South Mississippi Electric Power Association	Jerry W Johnson		
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	Cleco Power LLC	Matthew D Cripps	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Abstain	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn		

6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Thomas Saitta		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Abstain	
6	OTP Wholesale Marketing	Bruce Glorvigen	Negative	
6	Progress Energy	James Eckelkamp		
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	RRI Energy	Trent Carlson	Negative	View
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
8		James A Maenner	Affirmative	

8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Abstain	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Negative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	North Carolina Utilities Commission	Kimberly J. Jones	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray		
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Ballot Results	
Ballot Name:	Project 2007-01: Underfrequency Load Shedding_sb_in
Ballot Period:	9/24/2010 - 10/4/2010
Ballot Type:	Successive
Total # Votes:	270
Total Ballot Pool:	315
Quorum:	**85.71 % The Quorum has been reached**
Weighted Segment Vote:	81.72 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	89	1	64	0.821	14	0.179	7	4
2 - Segment 2.	10	0.8	7	0.7	1	0.1	0	2
3 - Segment 3.	76	1	47	0.797	12	0.203	6	11
4 - Segment 4.	26	1	18	0.818	4	0.182	2	2
5 - Segment 5.	57	1	29	0.744	10	0.256	7	11
6 - Segment 6.	36	1	16	0.667	8	0.333	1	11
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.5	4	0.4	1	0.1	1	1
9 - Segment 9.	7	0.5	5	0.5	0	0	0	2
10 - Segment 10.	7	0.6	6	0.6	0	0	0	1
Totals	**315**	**7.4**	**196**	**6.047**	**50**	**1.353**	**24**	**45**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	Arizona Public Service Co.	Robert D Smith	Negative	View

1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Affirmative	
1	Baltimore Gas & Electric Company	John J. Moraski	Abstain	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Negative	View
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	View
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Commonwealth Edison Co.	Daniel Brotzman	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Negative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	

1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Abstain	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lake Worth Utilities	Walt Gill	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	Metropolitan Water District of Southern California	Ernest Hahn	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Affirmative	View
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	

1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Douglas G Peterchuck	Negative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Mark Sampson		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	View
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	

1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Abstain	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	View
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Jason L. Murray		
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Transmission Corporation	Faramarz Amjadi		
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	

2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana	Affirmative	View
3	Arizona Public Service Co.	Thomas R. Glock		
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson		
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Negative	View
3	ComEd	Bruce Krawczyk	Negative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	View
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	

3	Dominion Resources Services	Michael F Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Negative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Abstain	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Abstain	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Los Angeles Department of Water & Power	Kenneth Silver		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C Parent	Negative	View
3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of	Steven M. Jackson	Affirmative	

	Georgia			
3	Muscatine Power & Water	John S Bos	Affirmative	
3	New York Power Authority	Marilyn Brown		
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	North Carolina Municipal Power Agency #1	Denise Roeder	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	OTP Wholesale Marketing	Bradley Tollerson	Negative	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	View
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Mississippi Electric Power Association	Gary Hutson		

3	Southern California Edison Co.	David Schiada	Affirmative	
3	Springfield Utility Board	Jeff Nelson	Abstain	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power - Ohio	Kevin Koloini	Negative	
4	American Public Power Association	Allen Mosher	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	View
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	

4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
4	Y-W Electric Association, Inc.	James A Ziebarth	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	View

5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith		
5	East Kentucky Power Coop.	Stephen Ricker	Negative	
5	Entergy Corporation	Stanley M Jaskot		
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Abstain	
5	Green Country Energy	Greg Froehling		
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	Mark Aikens		
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Negative	
5	Otter Tail Power Company	Stacie Hebert	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		

5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Mark A Heimbach		
5	Progress Energy Carolinas	Wayne Lewis	Abstain	
5	PSEG Power LLC	David Murray	Affirmative	View
5	Reedy Creek Energy Services	Bernie Budnik		
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	South Mississippi Electric Power Association	Jerry W Johnson		
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Cleco Power LLC	Matthew D Cripps	Negative	View

6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Thomas Saitta		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker		
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Abstain	
6	OTP Wholesale Marketing	Bruce Glorvigen	Negative	
6	Progress Energy	James Eckelkamp		
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	View

6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson		
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	View
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Abstain	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	North Carolina Utilities Commission	Kimberly J. Jones	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray		
9	Public Service Commission of South	Philip Riley	Affirmative	

	Carolina			
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Standards Announcement

Successive Ballot and Non-binding Poll Results

Now available at: https://standards.nerc.net/Ballots.aspx

Standard Drafting Team Project Name (Project 2007-01)

A successive ballot for standards PRC-006-1 — Automatic Underfrequency Load Shedding and EOP-003-1— Load Shedding Plans, and the associated implementation plan ended **on October 4, 2010**.

Successive Ballot Results

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 85.71%
Approval: 81.72 %

Since at least one negative ballot included a comment, these results are not final. Another ballot (either a successive ballot or a recirculation ballot) must be conducted.

Violation Risk Factor (VRF) and Violation Severity Level (VSL) Non-binding Poll Results

For the non-binding poll of VRFs and VSLs, 84% of those who registered to participate provided an opinion; 68% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Next Steps

The drafting team will review the comments submitted with ballots and post its consideration of those comments.

Project Background

Major objectives:

1. Ensure UFLS programs are developed to provide an appropriate level of reliability (not least common denominator).
2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.
3. Address the issues raised by FERC Order 693 and other applicable orders.
4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

Project page: http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool submitting either an affirmative vote, a negative vote, or an abstention, and (2) a two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first (or successive) ballot, the results of that ballot shall stand. If, however, one or more members submit negative votes with reasons, another ballot shall be conducted. If the team makes significant changes to the standard, then another successive ballot must be conducted. If the team does not make any significant changes to the standard, then a final recirculation ballot is conducted.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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Consideration of Comments on Non-binding Poll — Underfrequency Load Shedding_ (Project 2007-01)
Date of Non-binding Poll: September 24, 2010 – October 4, 2010

Summary Consideration: A non-binding poll of the VRFs and VSLs proposed for PRC-06-1 – Underfrequency Load Shedding was conducted from September 23 – October 4, 2010 and achieved a quorum with 68% of those responding indicating support for the proposed VRFs and VSLs.

The majority of the comments received highlighted concerns with the WECC VSLs. Specifically, the comments indicated that the proposed WECC VSL EB2 High and Severe are identical. The SDT made the conforming changes to the WECC VSLs as requested by the commenters as well as other minor edits to improve the correlation in wording between the requirements and the VSLs in the WECC Variance for E.B.4 VSLs.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Robert D Smith Mel Jensen	Arizona Public Service Co. APS	1 5	Negative	The standard is complicated and too prescriptive. It does not allow enough flexibility to Planning Coordinator and does not account for safety nets.
Response: The SDT cannot fully consider the comment without additional detail. However, the SDT believes the approach taken provides the Planning Coordinators the greatest flexibility by defining what performance characteristics the UFLS program must meet to support system reliability rather than defining how the Planning Coordinators are to design the UFLS program.				
Scott Kinney Edward F. Groce	Avista Corp.	1 5	Negative	Per a request to the drafting team the HIGH VSL for E.B.2 in the WECC regional variance should be replaced with a MODERATE VSL.
Response: The VSL has been revised per the commenter's request.				
Donald S. Watkins Rebecca Berdahl Francis J. Halpin	Bonneville Power Administration	1 3 5	Negative	For E.B.2. BPA suggests deleting the proposed wording of the HIGH VSL and replace it with the wording from the proposed MODERATE VSL, resulting in a HIGH and SEVERE VSL that are identical.

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Brenda S. Anderson		6		
Response: The VSL has been revised per the commenter's request.				
Claudiu Cadar	GDS Associates, Inc.	1	Negative	1. Requirement. R8. The timing does not coordinate with the requirement 2. Requirement. R10. The SDT should provide clarification on the capacitor banks if the VSL should reflect the percentage of banks switched or (and) the proper percentage of steps switched 3. New requirement / measure. The standard should include a VSL pertaining the communication of UFLS program, design / event assessment to UFLS entities and TOs involved as required to the PCs.
Response: 1. The VSLs for R8 refer to days beyond the schedule (that is, date) specified by the Planning Coordinator to receive the data. We are not sure what the commenter says does not coordinate. 2. The SDT does not see how the R10 VSLs could be construed as other than the percentage of banks switched. 3. The aspect of communication to UFLS entities of the UFLS program has been included in R3 and its VSLs (severe VSL) as "notification of."				
Chifong L. Thomas Richard J. Padilla	Pacific Gas and Electric Company	1 5	Negative	The High and the Severe VSLs for Variance E.B.2 are essentially identical since there are only two parts or sub-bullets identified in Variance E.B.2. The drafting team should consider moving the current wording for the Moderate VSL to the High VSL.
Response: The VSL has been revised per the commenter's request.				
Laurie Williams	Public Service Company of New Mexico	1	Negative	During the development of the proposed VSLs for the Regional Variance for the WECC Interconnection, it was discovered that, because there are only two sub-bullets for Variance E.B.2, the HIGH and SEVERE VSLs for E.B.2 are essentially the same. This information along with other grammatical wording changes were provided to the drafting team prior to the posting for successive ballot, but were inadvertently omitted from the posted version of PRC-006-1. The suggested revisions to the VSLs for E.B.2 are to delete the proposed wording of the HIGH VSL and replace it with the wording from the proposed MODERATE VSL, resulting in a HIGH and SEVERE VSL.
Response: The VSL has been revised per the commenter's request.				
Catherine Koch	Puget Sound Energy, Inc.	1	Negative	The HIGH VSL for E.B.2 should be deleted and replaced with the wording from the proposed MODERATE VSL, resulting in a HIGH and SEVERE VSL.
Response: The VSL has been revised per the commenter's request.				
Tim Kelley	Sacramento Municipal	1	Negative	In the Regional Variance for the WECC Interconnection the HIGH and SEVERE VSLs for E.B.2 are nearly identical. Since there are only two sub-bullets for Variance E.B.2

Voter	Entity	Segment	Vote	Comment
Mike Ramirez Bethany Wright	Utility District	4 5		the suggested revisions to the VSL for E.B.2 are to replace the High VSL with the current language of the Moderate VSL and leave the Moderate VSL blank. With these issues addressed SMUD will support the VSL.
James Leigh-Kendall	Sacramento Municipal Utility District	3	Negative	In the Regional Variance for the WECC Interconnection the HIGH and SEVERE VSLs for E.B.2 are nearly identical. Since there are only two sub-bullets for Variance E.B.2 the suggested revisions to the VSL for E.B.2 are to replace the High VSL with the current language of the Moderate VSL and leave the Moderate VSL blank.
Response: The VSL has been revised per the commenter's request.				
Robert Kondziolka John T. Underhill Glen Reeves	Salt River Project	1 3 5	Negative	The HIGH and SEVERE VSLs for E.B.2 are the same.
Response: The VSL has been revised.				
Pawel Krupa Dana Wheelock Hao Li Michael J. Haynes	Seattle City Light	1 3 4 5	Negative Negative	The HIGH and SEVERE VSLs for E.B.2 are the same. We also concur with WECC's recommendation that a negative vote for the VRFs and VSLs be submitted with a comment that the HIGH and SEVERE VSLs for E.B.2 are the same.
Response: The VSL has been revised.				
Rich Salgo	Sierra Pacific Power Co.	1	Negative	Negative vote because "High" and "Severe" Violation severity levels for E.B.2 are the same. There should be a distinction.
Response: The VSL has been revised.				
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	Delete the proposed wording of the HIGH VSL and replace it with the wording from the proposed MODERATE VSL, resulting in a HIGH and SEVERE VSL. HIGH and SEVERE VSLs for E.B.2 are the same.

Voter	Entity	Segment	Vote	Comment
Response: The VSL has been revised per the commenter's request.				
John Tolo	Tucson Electric Power Co.	1	Negative	VRFs and VSLs should not be approved until such time that the concerns with the proposed PRC-006 standard are addressed
Response: The SDT has addressed comments received on the proposed standard. See the Consideration of Comments report.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	R3, R9 and R10 should not have high VRFs. UFLS is designed as a backstop to prevent cascading, blackouts, and instability should other measures fail. Many other things, such as an IROL violation, will have to occur before the BES ever reaches the need for UFLS actuation. NERC's definition of a High VRF requires a direct connection between violation of the requirement and cascading, blackout, or instability. Given that other things must happen (such as an IROL violation) these requirements do not meet the definition of a High VRF for lack of the direct connection.
Response: The SDT maintains that "high" is the appropriate VRF and disagrees that there is not a direct connection between an improperly or poorly designed UFLS program and blackouts. The commenter rightly acknowledges that "UFLS is designed as a backstop to prevent cascading, blackouts and instability." While it may be true that many other violations could or even would occur before UFLS actuation, UFLS is, nevertheless, as a backstop, still in the direct line of defense against blackouts.				
Henry Ernst-Jr	Duke Energy Carolina	3	Affirmative	There is a typographical error on the "High" VSL for EOP-003-2 Requirement R3. The phrase "or less" after 15% should be struck.
Response: The SDT agrees that this is an error, but must adhere to the scope of its supplemental SAR and refrain from any changes not specific to removing automatic UFLS. Please bring this to attention of Project 2009-03 SDT at an appropriate time.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	During the development of the proposed VSLs for the Regional Variance for the WECC Interconnection, it was discovered that, because there are only two sub-bullets for Variance E.B.2, the HIGH and SEVERE VSLs for E.B.2 are essentially the same. This information along with other grammatical wording changes were provided to the drafting team prior to the posting for successive ballot, but were inadvertently omitted from the posted version of PRC-006-1. The suggested revisions to the VSLs for E.B.2 are to delete the proposed wording of the HIGH VSL and replace it with the wording from the proposed MODERATE VSL, resulting in a HIGH and SEVERE VSL. The drafting team has indicated that the revised wording provided for the VSLs for the WECC variance will be utilized, however, we are urging that a negative vote for the VRFs and VSLs be submitted with a comment that the HIGH and SEVERE VSLs for E.B.2 are the same.
Response: The VSL has been revised per the commenter's request.				
Scott Peterson	San Diego Gas & Electric	3	Negative	Voting not because the HIGH and SEVERE VSLs for E.B.2 are the same
Response: The VSL has been revised.				

Voter	Entity	Segment	Vote	Comment
Janelle Marriott	Tri-State G & T Association, Inc.	3	Negative	Tri-State appreciates the hard work by the drafting team and its attempt to address the concerns of many entities by inserting a WECC variance. We also agree that a standard of this nature is necessary to ensure reliable operation of the Bulk Electric System. However, we believe that the functional entity responsible for developing and documenting the UFLS program should be the Regional Entity through its registration as the Reliability Assurer. The drafting team addressed earlier comments in that regard by stating that the drafting team had confirmed "that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5." We do not reach that same conclusion. We do not see any assigned function of the Planning Coordinator that includes UFLS plan development. The NERC Reliability Functional Model Technical Document-Version 5, however, does state that a representative task undertaken by the Reliability Assurer might be to "perform high-level evaluations, such as at a regional or Interconnection level, of protection systems as they relate to the reliability of the Bulk Electric System." FERC, when addressing PRC-006-0, also states in Order 693, Paragraph 1480 "The Commission expects that this function will pass from the regional reliability organization to the Regional Entity after they are approved." This comment would affect the Applicability section as well as nearly all the requirements in the continental standard and in the WECC variance.
Response: The SDT believes that the WECC variance specifically addresses this concern by requiring a single coordinated program in the WECC interconnection. The Planning Coordinators will need to work together on this coordinated, region-wide program. The SDT believes the Planning Coordinator is still the appropriate entity to perform this function. The assignment of these functions to the Planning Coordinator is consistent with the role as defined in the Functional Model version 5 which says that the Planning Coordinator is: "The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas…The Planning Coordinator is responsible for assessing the longer-term reliability of its Planning Coordinator area. While the area under the purview of a Planning Coordinator may include as few as one Transmission Planner and one Resource Planner, the Planning Coordinator's scope of activities may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities."				
James R. Keller Anthony Jankowski	Wisconsin Electric Power Marketing Wisconsin Energy Corp.	3 4	Negative	In our standard ballot comments, we recommend that R5 be strengthened to prevent conflicting UFLS programs. As such, the Violation Risk Factor for R5 should be changed to High as conflicting UFLS programs do not promote reliability.

Voter	Entity	Segment	Vote	Comment
Linda Horn	Wisconsin Electric Power Co.	5		
Response: The SDT maintains that "medium" is still the appropriate VRF for R5 and that two overlapping Planning Coordinators was not intended when the function was defined; however, because of the registration these scenarios exist. The SDT does not believe the standard should be adjusted since the tasks assigned to the Planning Coordinator align with the existing definition and tasks aligned with this entity in the current version of the Functional Model. If the case of two overlapping Planning Coordinators persists, it should behoove them to coordinate their designs in such fashion that a DP is not presented with a situation in which it is impossible to achieve compliance.				
Thomas J. Bradish Trent Carlson	RRI Energy	5 6	Negative	The two sub-bullets for Variance E.B.2, the HIGH and SEVERE VSLs for E.B.2 are essentially the same. The suggested revisions to the VSLs for E.B.2 are to delete the proposed wording of the HIGH VSL and replace it with the wording from the proposed MODERATE VSL, resulting in a HIGH and SEVERE VSL.
Response: The VSL has been revised per the commenter's request.				
Dennis Sismaet	Seattle City Light	6	Negative	In addition to the ballot of PRC-006-1 and EOP-003-2, a non-binding poll of the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is being conducted. WECC staff and WECC subject matter experts have reviewed the proposed VRFs and VSLs and recommend a negative vote with comment for the VRFs and VSLs. During the development of the proposed VSLs for the Regional Variance for the WECC Interconnection, it was discovered that, because there are only two sub-bullets for Variance E.B.2, the HIGH and SEVERE VSLs for E.B.2 are essentially the same. This information along with other grammatical wording changes were provided to the drafting team prior to the posting for successive ballot, but were inadvertently omitted from the posted version of PRC-006-1. The suggested revisions to the VSLs for E.B.2 are to delete the proposed wording of the HIGH VSL and replace it with the wording from the proposed MODERATE VSL, resulting in a HIGH and SEVERE VSL. The drafting team has indicated that the revised wording provided for the VSLs for the WECC variance will be utilized, however, we are urging that a negative vote for the VRFs and VSLs be submitted with a comment that the HIGH and SEVERE VSLs for E.B.2 are the same.
Response: The VSL has been revised per the commenter's request.				

Voter	Entity	Segment	Vote	Comment
William Mitchell Chamberlain	California Energy Commission	9	Negative	There appears to be a problem with the VSLs proposed for the WECC variance. I understand a change was agreed to by the drafting team but the change did not make it into this balloted version. I'm voting NO only to assist in making the agreed correction.
Response: The VSL has been revised per the commenter's request.				
Louise McCarren	Western Electricity Coordinating Council	10	Negative	Because there are only two sub-bullets for WECC Variance E.B.2, the HIGH and SEVERE VSLs for E.B.2 are essentially the same. This information along with other grammatical wording changes were provided to the drafting team prior to the posting for successive ballot, but were inadvertently omitted from the posted version of PRC-006-1. The suggested revisions to the VSLs for E.B.2 are to delete the proposed wording of the HIGH VSL and replace it with the wording from the proposed MODERATE VSL, resulting in a HIGH and SEVERE VSL. If these changes, along with other gamatical revisions to the VSLs submitted to NERC on September 24, for E.B.4 are made, WECC supports the VRFs and VSLs.
Response: The VSL has been revised per the commenter's request.				

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Consideration of Comments on Successive Ballot — Underfrequency Load Shedding (Project 2007-01)
Date of Successive Ballot: September 24, 2010- October 4, 2010

Summary Consideration: A successive ballot was conducted from September 24-October 4, 2010 and achieved a quorum and an overall weighted segment approval of 81.72%. There were some comments submitted with both affirmative and negative ballots, and all of those comments and the drafting team's consideration of those comments, are included in this report.

Some balloters suggested that the SDT clarify the term "regional boundaries" in Requirement R2 part 2.3. The SDT made a minor change intended to clarify that "regional boundaries" are the "regional entity area boundaries". The SDT considers this change to be a clarifying change that does not substantively change the standard.

Some comments indicated that the Planning Coordinator (PC) should be replaced by the Reliability Coordinator (RC). Wide Industry support exists for the Planning Coordinator as the correct Functional Model entity to develop the UFLS program based on its wide-area view and expertise in the studies necessary to assess UFLS program performance. In addition, the assignment of these functions to the Planning Coordinator is consistent with the role as defined in the Functional Model Version 5 which says that the Planning Coordinator is: "The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas…" The Reliability Coordinator is defined as: "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." The Reliability Coordinator is not the appropriate entity to establish and assess UFLS programs which is a planning function not a real-time function.

Several comments indicated a concern that Requirement R14 does not go far enough and in other cases is not necessary on the basis that it is an administrative requirement. The SDT added Requirement R14 in response to comments received during the initial ballot conducted in July, 2010 that it was necessary for the Planning Coordinators to involve the UFLS entities in the development of the UFLS program and schedule for implementation. The SDT believes the UFLS Entities should have input into the process as provided in Requirement R14, but Requirement R14 cannot go further to require mutual agreement or concurrence due to the problem that one entity's compliance would be dependent on what another entity does.

Some comments indicated that the Transmission Owners(TOs) in the applicability is confusing considering they are included in "UFLS Entities" and proposed to modify the applicability section to clarify the distinction between 4.2 and 4.3 in the Applicability Section. The SDT thinks that Requirement R10 clearly establishes what is required (and why) of the Transmission Owners: provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program determined by the Planning Coordinator(s).

Several comments indicated that Requirements R8, R9 and R10: should require that the format and schedule be agreed upon by all the parties involved. Including a requirement in a standard that requires that entities agree with one another is problematic. It is possible that such a requirement could lead to compliance concerns because to fulfill the obligation of the requirement an entity will be dependent on another organization to be in compliance with the requirement. The alternative is that including all entities could potentially lead to compliance issues if they cannot reach agreement making all entities non-compliant.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	(1) Requirement R3 should be modified, as stated below, to reflect the need for the Planning Coordinator to recognize and use existing UFLS programs, which have been in place and functional for perhaps decades, as a starting point, rather than 'starting over from scratch': " R3. Each Planning Coordinator shall consider the existing UFLS programs that are in place, and working with the UFLS entities and Transmission Owners , propose modifications to the UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, as needed to meet the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load - actual generation output) / (load)], of up to 25 percent within the identified island(s). " **Response**: The SDT expects that Planning Coordinators will not be developing modifications to UFLS programs unless an assessment pursuant to Requirement R4 identifies deficiencies that prevent meeting the performance characteristics in Requirement R3. Although the proposed revision suggests that Planning Coordinators consider existing programs, it does not provide any additional incentive beyond the practical incentive that already exists with the existing requirement. In addition, the SDT added explanatory examples in the implementation plan to illustrate that during the phase-in period a Planning Coordinator may validate the existing program against the performance requirements to ensure the performance characteristics in Requirement R3 are met. (2) Requirement 14 only requires Planning Coordinator to provide a written response to the written comments submitted by the UFLS entities and Transmission Owners before finalizing its UFLS program. While R14 is a step in the right direction, it still provides the Planning Coordinator the authority to develop and pursue items 14.1, 14.2 and 14.3 without active participation of the UFLS entities and Transmission Owners in the process. An opportunity to submit written comments and receive written response is not the same as active involvement. The language of R14 should be modified such that the Planning Coordinator is required to provide for greater involvement of and coordination with the UFLS entities and

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				Transmission Owners in developing items 14.1 -14.3. **Response**: A requirement that the Planning Coordinators provide for involvement of and coordination with the UFLS entities and Transmission Owners does not provide a clear measure as to what constitutes "involvement" and "coordination." Industry comments have supported that the Planning Coordinator is the correct Functional Model entity to develop the UFLS program based on its wide-area view and expertise in the studies necessary to assess UFLS program performance. The SDT believes the UFLS Entities should have input into the process as provided in Requirement R14, but cannot go further to require mutual agreement or concurrence due to the problem that one entity's compliance would be dependent on what another entity does. (3) The previous version included curves out to 10,000 seconds where generators trip frequencies had to be modeled. This version includes revised curves, which is ok; but, a clarification is needed on whether or not to include generators with trip times longer than 100 seconds **Response**: Requirement R3 indicates that simulations must be run for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached. The time axis on the graphs in Attachment 1 was reduced to reflect this requirement. It is not necessary to model underfrequency protection that would operate beyond the end of the simulation.
Paul B. Johnson Raj Rana Brock Ondayko Edward P. Cox	American Electric Power American Electric Power AEP Service Corp. AEP Marketing	1 3 5 6	Affirmative	In R2.3 suggest clarification be provided for the terms "regional boundaries"
Response: The SDT made a minor change intended to clarify that "regional boundaries" are the "Regional Entity area boundaries" in Requirement R3 part 2.3.				
Robert D Smith	Arizona Public Service Co.	1	Negative	The standard is complicated and too prescriptive. It does not allow enough flexibility to Planning Coordinator and does not account for safety nets.

Voter	Entity	Segment	Vote	Comment
Mel Jensen	APS	5		
Response: The SDT cannot fully consider the comment without additional detail. However, the SDT believes the approach taken provides the Planning Coordinators the greatest flexibility by defining what performance characteristics the UFLS program must meet to support system reliability rather than defining how the Planning Coordinators are to design the UFLS program.				
Paul Rocha	CenterPoint Energy	1	Negative	In response to previous CenterPoint Energy comments, the SDT admits that island identification is subjective; however, the SDT has not made any significant changes in PRC-006-1 Draft 5 to address the confusion on island identification. In addition, the recent Webinar (September 17, 2010) stated "PC must have some criteria (R1), though not necessary that the criteria produce islands." R2 requires a PC to identify one or more islands. Again from the Webinar; "One island must be the regional footprint (R2.3) so as to preserve existing coordination of UFLS at regional level." Since R1 does not require the criteria to produce islands and R2 only requires one island, i.e. the regional footprint could suffice, it appears R1 and R2 require activities that are unnecessary and produce no meaningful product and therefore offer no enhancement of reliability to the BES above the current Standard. A reliability standard should have clearly defined requirements. CenterPoint Energy believes the islanding requirements are low level facilitating requirements that are more appropriately and inherently monitored under various higher-level performance-based requirements. Essentially, requirements R1 and R2 should be deleted. Alternatively, if the SDT feels compelled, for whatever reason, to maintain the proposed islanding requirements, CenterPoint Energy proposes adding wording to R1 along the lines of the SDT comments in the Webinar (September 17, 2010) and the Consideration of Comments. That is, concerning the criteria required for R1, clarify that it is"... not necessary that the criteria produce islands" and that R1 "does not mean that islands must be identified from a Planning Coordinator's R1 criteria."
Response: Past system disturbances including the August 14, 2003 Northeast Blackout demonstrate the value of identifying and assessing islands that may form. Identification and assessment of islands other than along regional boundaries, where they may form, offers a significant enhancement to reliability and justification for Requirements R1 and R2. The identification of at least one island is essential to serve as the basis for designing and assessing the UFLS program. The intent of R1 is the identification of islands that may have more than an insignificant probability of occurring and it is therefore desirable to use these, if there are any, in assessing UFLS program performance. However, if none are identified by the R1 criteria, that is still acceptable and the region or interconnection alone will suffice as the basis for the design assessments. So the result of R2 should be at least one island as explained during the webinar. Again, the SDT recognizes that it is possible that the R1 criteria yield no islands which is further justification, besides regional coordination, for including Requirement R2 Part 2.3 as it is important that at least one island serve as the basis for designing the UFLS program.				

Voter	Entity	Segment	Vote	Comment
Danny McDaniel Bryan Y Harper Matthew D Cripps	Cleco Power LLC Cleco Utility Group Cleco Power LLC	1 3 6	Negative	In the Applicability section of PRC-006, Planning Coordinator should be changed to Reliability Coordinator. This would allow the entity which has the highest authority to determine what is best for its region. **Response**: Wide industry support exists for the Planning Coordinator as the correct Functional Model entity to develop the UFLS program based on its wide-area view and expertise in the studies necessary to assess UFLS program performance. In addition, the assignment of these functions to the Planning Coordinator is consistent with the role as defined in the Functional Model version 5 which says that the Planning Coordinator is: "The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas..." The Reliability Coordinator is defined as: "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." The Reliability Coordinator is not the appropriate entity to establish and assess UFLS programs which is a planning function not a real-time function. For EOP-003, R5, Severe VSL, please add the statement "as directed by the requirement" as noted in the other requirements VSL. **Response**: The proposed change is outside the scope of the supplemental SAR for this project to revise the requirements specific to Underfrequency Load Shedding in EOP-003-1 to remove inconsistencies and redundancies with PRC-006-1.
Robert Martinko Kevin Querry Kenneth Dresner Mark S Travaglianti	FirstEnergy Energy Delivery FirstEnergy Solutions FirstEnergy Solutions FirstEnergy Solutions	1 3 5 6	Affirmative	FE appreciates the SDT's hard work on this project and is casting an Affirmative vote. Also, we offer the following comments and suggestions: We anticipate that Planning Coordinators and UFLS Entities will work together to reach consensus on the implementation schedules. However, we still believe that the standard or implementation plan should explicitly afford the UFLS entity at least 12 months to implement any new capital equipment, and at least 3 months to implement setting changes on existing equipment. Also, we believe that the standard should explicitly require that the PC solicit input into the final draft of the program from its UFLS Entities. **Response**: Thank you for your support. The SDT expects that the Planning Coordinators will consider input from the UFLS entities when establishing their UFLS program and schedule for implementation per Requirement R14 Part 14.1. The SDT also expects that as the Planning Coordinators fulfill their role as described in the Functional Model, including coordinating with the Transmission Owners and Distribution Providers, they will not make unilateral decisions without considering

Voter	Entity	Segment	Vote	Comment
Douglas Hohlbaugh	Ohio Edison Company	4		the input from the UFLS entities (as provided for in Requirement R14 or otherwise). The SDT debated on whether to include a minimum implementation time frame as suggested, but concluded that selecting a minimum time could still not guarantee sufficient lead time, the time frame must be based on the scope of the program modifications on a case-by-case basis, and any particular time frame would be difficult to justify for a continent-wide standard. Lastly, in the rare case of any concerns among the UFLS entities of the PC's UFLS program, we suggest an enhancement to require that the PC have a dispute resolution process. To incorporate our comments above, we have the following proposed wording for Requirement R14: "R14. Each Planning Coordinator shall meet the following during the development of a new UFLS program and during subsequent revisions of the program [VRF: Low][Time Horizon: Long-Term Planning]: 14.1. Submit an initial draft of its UFLS program for review and feedback by the identified UFLS Entity before the UFLS program is finalized. 14.2. Assure that the schedule for implementation of a UFLS program affords the UFLS Entity at least 12 months to achieve compliance for any required capital equipment expenditures and installations, and at least 3 months for any required settings changes to existing equipment. 14.3. Have and implement a dispute resolution for cases where the UFLS Entity and the Planning Coordinator cannot reach agreement on the UFLS program. **Response:** The SDT thinks that adding a requirement to establish a dispute resolution process would go too far in prescribing "how" the Planning Coordinator will fulfill its role rather than what needs to be accomplished to achieve reliability.
Claudiu Cadar	GDS Associates, Inc.	1	Negative	1. Applicability. 4.3. We do not agree with prior SDT response to comment. While SDT response indicates that 4.3 is intended for TOs that may need to switch equipment other than load, however we consider that 4.3 is a redundant assignment since reference to TOs controlling UFLS equipment already included in 4.2.2. We consider that TOs that own control / operate elements other than the UFLS equipments but identified in an UFLS program, should be considered as part of the same category "UFLS entities". However, if SDT wants to split the TOs into two categories based on the end-use load, and elements other than UFLS equipments, 4.3 should be reformulated to reflect the difference in between the two (this will help to point out to what TOs are the requirements applicable). We suggest adjusting 4.3 such as "Transmission Owners that own Elements identified in the UFLS program other than the UFLS equipment as established by the Planning Coordinators." **Response:** The SDT thinks that the Transmission Owner applicability is sufficiently

Voter	Entity	Segment	Vote	Comment
				clear and that Requirement R10 clearly establishes what is required (and why) of the Transmission Owners: provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program determined by the Planning Coordinator(s). 2. Effective Date. 5. Depending on when this standard becomes mandatory and enforceable, it may fall between entities' budgeting periods. An 18 months implementation would allow for all entities to budget the funds necessary to implement the standard. **Response:** The SDT expects that the Planning Coordinators will consider input from the UFLS entities when establishing their UFLS program and schedule for implementation per Requirement R14 part 14.1. The SDT also expects that as the Planning Coordinators fulfill their role as described in the Functional Model, including coordinating with the Transmission Owners and Distribution Providers, they will not make unilateral decisions without considering the input from the UFLS entities (as provided for in Requirement R14 or otherwise). The SDT debated on whether to include a minimum implementation time frame as suggested, but concluded that selecting a minimum time could still not guarantee sufficient lead time, the time frame should be based on the scope of the program modifications on a case-by-case basis, and any particular time frame would be difficult to justify for a continent-wide standard. 3. Requirements. R2.3. The added wording, which although brings some clarification in how the regional boundaries will be established, can be confusing with respect to the elements included in the UFLS program when for simulation purposes there will be elements either integrated or excluded; the elements comprised in the assessment may not entirely match the list of elements identified by the UFLS program. We consider that the models used in simulation should reflect the correct topology and structure of the BES. **Response:** The R2.3 added wording (the last sentence of R2.3) is necessary because the contour of some sections of the Regional Entity boundaries in the Eastern Interconnection may cause difficulties when attempting to simulate each Regional Entity area as a single contiguous island. However, once island boundaries are adjusted by mutual consent, and such islands are thereby defined for purposes of UFLS design assessments, there should be no confusion as to which elements are in an island and which are outside, though it is true that UFLS

Voter	Entity	Segment	Vote	Comment
				program(s) of Planning Coordinator(s) of a different region may be represented in a portion of a Regional Entity island with adjusted boundaries. 4. Requirements. R8. We disagree with SDT response on previous comment. While all this flow of data requires coordination among the UFLS entities, TOs that own equipment as identified in the UFLS program and PCs, we suggest that the proper format and schedule should be agreed upon by all these parties involved, where the standard should specifically state this. Comment applies also to R9 and R10. **Response:** UFLS entities and Transmission Owners have opportunity for input on the schedule for implementation as provided for by R14. The requirement to supply data (R8) is not onerous and the SDT believes that as the Planning Coordinator may be receiving data from many entities, the PC should be able to determine the schedule and format for efficiency in processing the received data. While the standard does not set a certain schedule, can the SDT explain the timing in the corresponding VSL for R8 **Response:** The VSLs for R8 refer to days beyond the schedule (that is, date) specified by the Planning Coordinator to receive the data. Requirement R8 says that the Planning Coordinator will establish the format and schedule. The corresponding VSL is an after-the-fact element once the requirement has been violated and since the requirement is "time sensitive" the VSL must establish various levels of severity for non-conformance to the requirement. The VSLs were developed using the SDT Guidelines and conform to the NERC and FERC guidelines for VSLs. 5. Requirements. R5, R13. The addition of bullet-pointed methods to approach the coordination of the design assessment or event assessment should be followed by a comment period and written response such in case PCs have not reach the same conclusions of its own individual assessment, otherwise there will be no coordination in that case. We also suggest replacing the bullet points with numbers such as 5.1, 5.2, 5.3 / 13.1, 13.2, 13.3. **Response:** Unfortunately, a comment period cannot assure coordination either. A previous draft of the standard required Planning Coordinators to reach concurrence, but this was found to be unacceptable to a wide spectrum of industry commenters. Bullets points in a standard indicate that the entity has various options to select from to fulfill its duties as clarified by the term that precedes the list of bullets "through or by one of the following" in Requirement R5 and Requirement R13. Numbers in the standard establish a "must" list. The entities would be required to

Voter	Entity	Segment	Vote	Comment
				meet all the items on a numbered list. 6. New requirement / measure. The standard should include a requirement so the PCs to communicate their UFLS program, design / event assessment to UFLS entities and TOs involved (which own elements identified by the program or assessment). Appropriate measures for retaining evidence should be also included. **Response:** Requirement R3 includes notification to the UFLS entities of the UFLS program and schedule for implementation. Event assessments do not directly affect UFLS entities unless a redesign is in order in which case R3 would again require notification. Evidence retention is specified in the Compliance Section, D 1.2.
Michelle Rheault Greg C Parent Daniel Prowse	Manitoba Hydro	1 3 6	Negative	The current draft standard did not consider most Manitoba Hydro and MRO concerns submitted during the commenting period.
Response: The SDT considered all comments received during development of the standard. The SDT made many changes to the standard in response to industry comments. The SDT acknowledges that it did not modify the standard in response to every comment, but also notes that explanations were provided whenever the SDT decided not to modify the standard in response to comments.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	While the TPL note “b” approach has improved, MidAmerican has concerns that including the wording “review and acceptance” goes beyond the FERC Order 890 Order, process, and intent of including the an open review. Therefore, to align with FERC Order 890, the “review and acceptance” should be replaced with “subject to comment”. Anything more exceeds FERC Order 890 and the reason why the review process was included. In the end, Transmission Owning and Operating entities must have final say in the operation of the grid. Entities can comment, but cannot obstruct Transmission Owning and Operating entities from properly operating the grid or reliability could be reduced.
Response: The phrase “review and acceptance” does not appear in PRC-006-1. The SDT believes this comment may have been intended for another standard and inadvertently submitted as a comment to this ballot.				
Richard L. Koch	Nebraska Public Power District	1	Affirmative	Modeling criteria may need to be changed with the approval of PRC-024-1.

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Response: Thank you for your support. The SDT understands that the generator off-nominal frequency protection coordination curves that will be included in PRC-024 are the same as what is currently included in PRC-006. The intent by both teams is that these curves will continue to be coordinated going forward.				
Kenneth D. Brown Jeffrey Mueller David Murray James D. Hebson	Public Service Electric and Gas Co. Public Service Electric and Gas Co. PSEG Power LLC PSEG Energy Resources & Trade LLC	1 3 5 6	Affirmative	The PSEG Companies' vote to approve is based on the following understanding of the standards. The Planning Coordinator is responsible for development and coordination of the overall UFLS programs and assessments. Support from the Transmission Owners and other entities consists of providing the Planning Coordinator with data such as forecasted loads and installed UFLS capability upon request, and to maintain and modify the capability as required, with the understanding that the PRC-006-1 Requirement 14 process will address any TO or other entity concerns. Regarding requirements specified in PRC-006-1 Requirement 10, Planning Coordinators will need to confirm that any automatic switching of capacitors, reactors and particularly transmission lines will not be a detriment to local conditions as specified by the Transmission Owners. Switching of specific transmission lines could result in the further reduction of load in an island, compounding the overvoltage effects.
Response: The SDT agrees. Thank you for your comments and support of the standard.				
Keith V. Carman Janelle Marriott	Tri-State G & T Association, Inc.	1 3	Negative	Tri-State appreciates the hard work by the drafting team and its attempt to address the concerns of many entities by inserting a WECC variance. We also agree that a standard of this nature is necessary to ensure reliable operation of the Bulk Electric System. However, we believe that the functional entity responsible for developing and documenting the UFLS program should be the Regional Entity through its registration as the Reliability Assurer. The drafting team addressed earlier comments in that regard by stating that the drafting team had confirmed "that the Planning Coordinator is the appropriate entity to design UFLS and conduct the other UFLS related activities based on the definition of the Planning Coordinator in the Functional Model Version 5." We do not reach that same conclusion. We do not see any assigned function of the Planning Coordinator that includes UFLS plan development. The NERC Reliability Functional Model Technical Document-Version 5, however, does state that a representative task undertaken by the Reliability Assurer might be to "perform high-level evaluations, such as at a regional or Interconnection level, of protection systems as they relate to the reliability of the Bulk Electric System." FERC, when addressing PRC-006-0, also states in Order 693, Paragraph 1480 "The Commission expects that this function will pass from the regional reliability organization to the Regional Entity after they are approved." This

Voter	Entity	Segment	Vote	Comment
				comment would affect the Applicability section as well as nearly all the requirements in the continental standard and in the WECC variance.
Response: The SDT believes that the WECC variance specifically addresses this concern by requiring a single coordinated program in the WECC interconnection. The Planning Coordinators will need to work together on this coordinated, region-wide program. The SDT believes the Planning Coordinator is still the appropriate entity to perform this function. In addition, the assignment of these functions to the Planning Coordinator is consistent with the role as defined in the Functional Model version 5 which says that the Planning Coordinator is: "The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas…The Planning Coordinator is responsible for assessing the longer-term reliability of its Planning Coordinator area. While the area under the purview of a Planning Coordinator may include as few as one Transmission Planner and one Resource Planner, the Planning Coordinator's scope of activities may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities."				
John Tolo	Tucson Electric Power Co.	1	Negative	The primary concern identified is that the current proposal does not require coordination within the interconnection. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections - no such justification has been provided.
Response: The WECC variance included with this most recent revision of the standard address most, if not all, of these concerns, which are specific to the WECC interconnection. Please review the justification for the WECC variance included with the ballot of draft 5 of the standard.				
Allen Klassen	Westar Energy	1	Negative	Not enough time for study completion and implementation.

Voter	Entity	Segment	Vote	Comment
Response: The SDT believes that there is ample time to complete the study. The implementation schedule is set by the Planning Coordinator, not the standard.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	We thank the drafting team for its response to the issues raised during the last ballot. Notwithstanding our 'AFFIRMATIVE' vote on this occasion, we continue to have several concerns as follows: We believe the generating unit and facility capacities specified in Requirement R4 are not appropriate. In our view, as more renewable energy projects are developed in the future, the significance of generating units and facilities throughout North America that do not meet those thresholds will increase, as is the case in Ontario at present. We will pursue this issue as suggested, as a variance to the NPCC regional UFLS standard which is currently under development where we hope it will be adequately addressed. **Response**: Thank you for your support of the standard. We believe that pursuing this issue in a regional standard is appropriate if the NPCC system requires lower thresholds. Further, we view the generator overfrequency trip modeling curve as overly conservative. Having higher overfrequency trip thresholds is highly desirable since this will provide greater flexibility to the PC in designing its UFLS program in situations where over-generated islands are formed. We will pursue this matter further under Project 2007-09 - Generator Verification, as part of the continued development of PRC-024-1. We expect that if changes to this curve are made in PRC-024-1, they will be reflected in PRC-006-1. **Response**: Thank you for your support of the standard. We believe that pursuing this issue with the Generator Verification SDT is an appropriate method for pursuing your concern. If the overfrequency trip curve in PRC-024 is raised a SAR should be submitted to request corresponding changes to PRC-006. Finally, we would like to know what recourse a PC will have if it is unable to design an effective UFLS program due to the tight constraints imposed by the UFLS performance characteristics. **Response**: The SDT does not believe that designing a UFLS program that satisfies the performance curves for the required imbalance level will be a problem.
Jason L Marshall	Midwest ISO, Inc.	2	Negative	While we continue to agree with the purpose statement of the draft UFLS standard, we have continuing concerns regarding the draft standard that have not been resolved. We believe the standard goes much farther than the purpose statement, is too prescriptive, and includes too many administrative requirements. R14 is an

Voter	Entity	Segment	Vote	Comment
				administrative requirement that establishes a stakeholder process which has no demonstrated reliability benefit. It should be removed. UFLS relays already are installed and coordinated today. The standard needs should be simplified to reflect this reality. We believe the standard should not be more complicated than establishing a requirement to have coordinated UFLS relays and making pertinent information available on the UFLS relays and program to the reliability entities with a need to know. The purpose can be accomplished in many fewer requirements than the 14 proposed requirements. **Response**: The simplified standard requirements suggested in this comment would constitute a fill-in-the-blank standard similar to the existing PRC-006-0 which the Commission did not approve in Order No. 693. The SDT believes the proposed standard does recognize existing programs and expects that Planning Coordinators will not be developing modifications to UFLS programs unless an assessment pursuant to Requirement R4 identifies deficiencies that prevent meeting the performance characteristics in Requirement R3. Ensuring coordination of UFLS relays is not as easy as just saying that UFLS relays shall be coordinated. The SDT believes the standard achieves a reasonable balance between prescription and autonomy. Though R14 is administrative and procedural, it has the support of many industry commenters as a means by which Distribution Providers and Transmission Owners may have input on what they will be required to implement and when. While we agree that it makes sense to develop a frequency envelope to ensure it is coordinated across the Interconnection, we do not believe there is a need for Volts/Hz limit in 3.3. **Response**: The SDT believes there is a need for V/Hz requirements because shedding load will cause voltages to climb, which may cause excitation systems / voltage regulators to reach the end of their range, which can lead to a V/Hz condition that could cause generators to trip through GSU protection or other similar protection systems. Tripping of generation due to preventable V/Hz conditions may exacerbate an already precarious underfrequency condition. The SDT believes that this threat to UFLS effectiveness should not be overlooked. We continue to disagree with the need to identify islands. While some areas of the BES have obvious islands such as the Florida peninsula, most of the BES does not form obvious islands and trying to predict how islands will form is arbitrary and unnecessary and provides no clear benefit to reliability. Other requirements that build on this islanding concept are unnecessary as well. For instance, we do not

Voter	Entity	Segment	Vote	Comment
				believe it is necessary or even beneficial to perform dynamic simulations of the UFLS program in areas that do not have natural islands. These simulations involve contingencies to such extremes that it stretches the limits of the analysis software and provides arbitrary results with questionable value. While these studies have been attempted in the past by some NERC regions, some of these very studies have stated within their documentation that the island boundaries are completely arbitrary and don't correspond to any historical or conceivable islanding event. Furthermore, an effective UFLS scheme can be designed without simulations. **Response**: Past system disturbances including the August 14, 2003 Northeast Blackout demonstrate the value of identifying and assessing islands that may form. Identification and assessment of islands other than along regional boundaries, where they may form, offers a significant enhancement to reliability and justification for Requirements R1 and R2. Islands, whether arbitrary or real, also need to be identified to conduct UFLS design assessments. The intent of R1 is the identification of islands that may have more than an insignificant probability of occurring and it is therefore desirable to use these, if there are any, in assessing UFLS program performance. However, if none are identified by the R1 criteria, that is still acceptable and the region or interconnection alone will suffice as the basis for the design assessments. The SDT agrees that effective UFLS programs can be designed without simulations. However, simulations are necessary to at least supply the evidence that a UFLS design can be effective and may supply insights toward a more effective design. We question the need for R11 and R13 given NERC's recent efforts to develop an event analysis process and focus on becoming a learning organization. NERC's process already compels registered entities to do their own event investigation and UFLS triggers are already included in Category 2. Why do we need requirements for event analysis in this standard as well? **Response**: The SDT originally planned to cover event analysis requirements through the established NERC governance as suggested, but subsequent conversation with FERC staff led to the conclusion that requirements in PRC-009-0, an existing FERC approved standard which will be retired with the adoption and regulatory approval of PRC-006-1, cannot simply be dropped. As a result, the SDT found it necessary to include the event analysis requirements of PRC-009 as described in R11 and R13.

Voter	Entity	Segment	Vote	Comment
Bruce Krawczyk	ComEd	3	Negative	There remains confusion about multiple Planning Coordinators with potentially different criteria enforcing differing mitigations within postulated islands that may overlap amongst any number of PCs. WECC made this same argument and was subsequently granted a separate set of Requirements to alleviate this confusion. It doesn't seem fair that the Eastern Interconnection wouldn't also be able to enjoy that same degree of certainty and ability to adequately plan. **Response**: The WECC Variance was added in response to a specific request from the WECC entities. The SDT notes however, that in general industry comments raised significant concerns with the compliance implications of forcing entities to reach agreement. The SDT acknowledges that if a Distribution Provider's area is covered by more than one Planning Coordinator, it is possible for the Distribution Providers to be required to adhere to different programs in different parts of its area. This is most likely to occur when a Distribution Provider area includes portions of more than one region. Should this situation occur, the process defined in Requirement R14 allows for UFLS Entities to provide input to the Planning Coordinators regarding the impact of proposed UFLS program modifications. Exelon's previously stated concern that there is not a requirement that all load participate equally in maintaining frequency has not been addressed. **Response**: The SDT continues to believe that this is a detail best addressed during the UFLS program design. There is a lot of confusion about the interaction of generation with load regarding this frequency standard. This standard states that there is no applicability to generation owners or operators, yet the PCs are required to obtain data from GOs. There is also a V/Hz requirement that seems to apply to generators although it is not specifically stated as such. **Response**: The Planning Coordinators are not required to model the generator underfrequency and overfrequency trip points until PRC-024 is approved, after which time the data will become available. The V/Hz requirement is a requirement on the Planning Coordinator to assess V/Hz condition in simulations and does not place any requirements on the Generator Owner, nor does it require the Planning Coordinator to obtain any data from the Generator Owner. There needs to be coordination between load and generation to maintain frequency across an interconnection or within an island and that cooperation is not addressed in this standard. There may be another standard in development that applies to

Voter	Entity	Segment	Vote	Comment
				generation addressing some or all of the elements to maintain frequency and perform adequate studies, but that should not be assumed to be the case in the development of an enforceable standard. There is confusion regarding Exhibit 1 and how the generator curve requirements and load shape requirements are to be mapped into future requirements. **Response**: The coordination between load and generation is being achieved through the coordination of standards PRC-006 and PRC-024. The UFLS SDT and the Generator Verification SDT have coordinated the requirements in the two standards to achieve the necessary reliability objective that generator tipping will not impinge on UFLS program effectiveness. Following the previous ballot the SDT added annotation to Attachment 1 to clarify application of the curves Islanding criteria should be consistent and developed through a standards process that allows development through a stakeholder process. This proposed standard circumvents the NERC process and requires PCs to unilaterally impose criteria without sufficient guidance or feedback. There should be a single set of criteria for the determination of an island, which is consistent across the interconnection, unless a specific geographic or regional exception is identified. The standard should state that even if differing islanding criteria are allowed for each PC, the Planning Coordinator with responsibility for the footprint should have sole authority for determining and modifying the criteria within that footprint. **Response**: The SDT believes that due to differences in physical system characteristics between regions, issues such as how islands are identified are best left to the Planning Coordinators. Comments received during development of the standard indicate industry support for this approach. It is certain that there are many valid approaches to criteria for island identification and any one may be as good as another. A single set of criteria is not appropriate. The standard only requires that Planning Coordinators establish criteria to identify islands for the purpose of conducting their UFLS design assessments, thus the Planning Coordinators will not be unilaterally imposing criteria on other entities. The SDT believes the standard already provides each Planning Coordinator with sole responsibility for developing island identification criteria for its area, although to provide coordination of UFLS programs, a Planning Coordinator may be required to assess an island identified through application of an adjacent Planning Coordinator's criteria in an and adjacent area. There should be some recognition in the standard that UFLS schemes currently exist and effort should be made to avoid needlessly changing relays or settings on

Voter	Entity	Segment	Vote	Comment
				many thousands of installations if some arbitrary and common set points were to be determined by the PC, thus causing needless expense. It is likely desirable to have slightly different settings for UFLS across a footprint so as to not create load changes that are too abrupt. **Response**: The SDT agrees that arbitrary changes to UFLS programs could result in needless effort and expense. The SDT expects that Planning Coordinators will not be developing modifications to UFLS programs unless an Assessment pursuant to Requirement R4 identifies deficiencies that prevent meeting the performance characteristics in Requirement R3. The process defined in Requirement R14 allows for UFLS Entities to provide input to the Planning Coordinators regarding the impact of proposed UFLS program modifications.
David A. Lapinski David Frank Ronk James B Lewis	Consumers Energy	3 4 5	Affirmative	While we recognize that changes to R2 of EOP-003-2 are not within the scope of the SAR, we are of the opinion that R2 needs significant revision. The vague concept of "Shall establish plans..." could be satisfied by a document that says that UVLS shall be installed by January 1, 2052. It is a plan, but probably not a very good one. R2 seems to establish no requirement for a good plan, no requirement that a plan be implemented, etc. If it is possible for the PRC-006-1 SDT to pass along this comment to the SDT working on EOP-003, it would be appreciated.
Response: Thank you for your comments and support. The SDT that is working on revising EOP-003 will be posting the proposed revisions to EOP-003 at a future date. You will have an opportunity at that time to provide your comments on EOP-003.				
Henry Ernst-Jr	Duke Energy Carolina	3	Affirmative	There is a typographical error on the “High” VSL for EOP-003-2 Requirement R3. The phrase “or less” after 15% should be struck.
Response: Thank you for your support. The proposed change is outside the scope of the supplemental SAR for this project to revise the requirements specific to Underfrequency Load Shedding in EOP-003-1 to remove inconsistencies and redundancies with PRC-006-1. The SDT suggests that the commenter submit this concern to the team working on project 2009-03.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	Curves rather than a table results in unrealistic compliance expectations.
Response: The SDT converted the performance characteristics for frequency-time limits from tabular format to curves in response to industry comments. The SDT also has added the equations in tabular format that define the curves in order to address compliance concerns associated with the lack of precision associated with reading values off the graph. The SDT believes that providing the requirement in both tabular and graphical format should address any compliance concerns related to the curves.				

Voter	Entity	Segment	Vote	Comment
James R. Keller Anthony Jankowski Linda Horn	Wisconsin Electric Power Marketing Wisconsin Energy Corp Wisconsin Electric Power Co.	3 4 5	Negative	During the 9/17/10 Webinar we commented that our company, as a DP, is covered by two Planning Coordinators. Other entities also indicated a similar situation during the Webinar. In response, the SDT stated that this situation was not taken into consideration and further commented that this situation appears to be a registration issue. The reality is this situation exists and the standard as written does not have a strong enough mechanism to prevent two or more Planning Coordinators from designing respective UFLS programs with conflicting settings for the UFLS Entity that the two Planning Coordinators cover. **Response**: Two overlapping Planning Coordinators was not intended when the function was defined; however, because of the registration these scenarios exist. The SDT does not believe the standard should be adjusted since the tasks assigned to the Planning Coordinator align with the existing definition and tasks aligned with this entity in the current version of the Functional Model. If the case of two overlapping Planning Coordinators persists, it should behoove them to coordinate their designs in such fashion that a DP is not presented with a situation in which it is impossible to achieve compliance. The Planning Coordinator coordination in Requirement R5 appears to be the standard's main method for attempting to prevent conflicting UFLS program designs. However, the sub-bullets in R5 are a choice of three options, the last of which does not force a resolution of Planning Coordinators' differences. The first two sub-bullets should not be choices, but required actions. The last sub-bullet needs to be removed as it does not force a resolution when there are conflicts/differences in UFLS program designs. R13 should be revised to follow this same concept. **Response**: During development of this standard the industry comments raised significant concerns with the compliance implications of forcing entities to reach agreement. The SDT agrees that the first two bullets in Requirements R5 and R13 are preferable methods for demonstrating compliance. However, the SDT also believes that the third bullet provides Planning Coordinators a necessary method to comply without reliance on other entities and the SDT expects providing recommendations to the other Planning Coordinators and the ERO will lead to resolution of issues. In response to comments and during the Webinar, the SDT stated that it anticipates the assumption of burden by UFLS Entities for generators that do not conform to the PRC-024 underfrequency/overfrequency tripping curves will not be significant. We continue to believe that ignoring generator responsibilities due to possible small

Voter	Entity	Segment	Vote	Comment
				burden is not acceptable, as in some areas the burden may be significant and unwarranted without an obligation on the generator. Since the standard requires the study of the effects of non-conforming generators, the SDT must feel that the effects of non-conforming generators may be significant. **Response**: The PRC-024-1 curves were chosen in view of permissible off-nominal frequency time durations advised by major generator manufacturers and in view of existing regional guidelines on generator off-nominal frequency protection. The team's expectation, therefore, is that the amount of non-conforming generation will be small. Some regions currently have generator under-frequency tripping characteristic guidelines that are of higher frequency and of shorter time delay than the PRC-024-1 Attachment 1 curve allowing generators to trip sooner or at higher frequencies. We expect that this may initially produce a significant quantity of non-conforming generators in some regions due to the settings of under-frequency relays, but that there should generally be no particular technical reason for not resetting these relays to conform to the PRC-024-1 Attachment 1 curves once that standard becomes enforceable. The continent-wide standard does not prevent regional standards from requiring compensatory load shedding by Generator Owners thus shifting the burden of responsibility. It is for the above reasons that we continue to believe that the UFLS program which is ultimately implemented by the UFLS Entity needs to be mutually agreed to between the Planning Coordinator and the UFLS entity. **Response**: Requiring mutual agreement or concurrence between entities was found to be unacceptable by many industry commenters due to one entity's compliance being dependent on what another entity does. Industry comments have supported that the Planning Coordinator is the correct Functional Model entity to develop the UFLS program based on its wide-area view and expertise in the studies necessary to assess UFLS program performance. The SDT also agrees that the UFLS Entities should have input into the process and has added Requirement R14 to address this concern.
Michael Ibold Liam Noailles David F. Lemmons	Xcel Energy, Inc.	3 5 6	Negative	Xcel Energy continues to believe that Generators Owners should be subject to this standard. The role of Generator response to under frequency conditions is integral to under frequency plan performance. Comments to previous responses indicate that a pending PRC-024, applicable to GOs, would resolve many of these concerns however the gap should be closed in this standard (PRC-006) until the PRC-024 standard is approved.

Voter	Entity	Segment	Vote	Comment
Response: In view of the scope of PRC-024 and the already established coordination between it and PRC-006, the SDT does not wish to introduce double jeopardy for Generator Owners. Filling the gap until PRC-024 is approved would lead to confusion regarding development of the same requirement in two standards, would be inefficient, cause extra complexity, and likely take longer than the time frame for approval of PRC-024.				
James A Ziebarth	Y-W Electric Association, Inc.	4	Negative	Y-WEA appreciates the efforts of the SDT in respect to addressing previous comments calling for region-wide UFLS program development. However, Y-WEA concurs with Tri-State G&T in believing that the duties performed by the Planning Coordinator under this proposed standard would be more appropriately carried out by the Reliability Assurer. In addition, the SDT's addition of R14 to the proposed standard is helpful in requiring that the parties developing UFLS programs respond to comments by the UFLS entities, but there is presently no requirement for the UFLS developers to solicit comments from the UFLS entities. For this reason, Y-WEA proposes that R14 be replaced with the following: R14. Each Planning Coordinator shall conduct a comment period before finalizing its UFLS program and shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following the comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following [VRF: Lower][Time Horizon: Long-term Planning]: 14.1. UFLS program, including a schedule for implementation 14.2. UFLS design assessment 14.3. Format and schedule of UFLS data submittal
Response: The SDT believes that the WECC variance specifically addresses this concern by requiring a single coordinated program in the WECC interconnection. The Planning Coordinators will need to work together on this coordinated, region-wide program. The SDT believes the Planning Coordinator is still the appropriate entity to perform this function.				
Michael J. Haynes	Seattle City Light	5	Affirmative	Rationale: SCL SME concur with WECC's recommendation to approve both proposed PRC-006-1 - Automatic Underfrequency Load Shedding and EOP-003-2 - Load Shedding Plans. Proposed PRC-006 includes a Regional Variance for the Western Interconnection that requires Planning Coordinators to continue regional coordination for Underfrequency Load Shedding Plans, an element missing from the PRC-006 standard balloted in July 2010. Proposed EOP-003-2 removes automatic Uunderfrequency Load Shedding requirements from EOP-003-2, as they are redundant with PRC-006-1, and to remove from the Balancing Authority requirements for which they are not responsible.
Response: Thank you for your comments and support of the standard.				
Jim D.	JDRJC	8	Negative	Too many administrative requirements and overly complex

Voter	Entity	Segment	Vote	Comment
Cyrulewski	Associates			
Response: The SDT cannot fully consider the comment without additional detail. However, the SDT believes the approach taken provides the Planning Coordinators the greatest flexibility by defining what performance characteristics the UFLS program must meet to support system reliability rather than defining how the Planning Coordinators are to design the UFLS program.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	NPCC supports the standard however some reservation exists about a potential "fill in the blank" nature of the requirements. The PC is required to have a UFLS program and this program is required to be followed by the TOs and GOs even though FERC has not seen the specific program. There are targets specified in the standard that a PC must meet however it should be recognized that there are many different potential programs that may meet the target and contain other concerns. It would have been more desirable to have only the basic program targets for the PCs to have in their individual programs in this standard and then, in the companion Regional Standards that the ERO already directed the regions to develop, Have the specific PC program requirements and the specific requirements on the TOs and GOs to follow them. As written currently, the standard requires the TOs and GOs to follow some unapproved and not commission filed program. Compliance with this may be problematic.
Response: Many regions are developing regional standards or have regional criteria that establish the region's UFLS program requirements. The PC is required to notify the UFLS entities of the UFLS program requirements and schedule for implementation as required in Requirement R3. The UFLS entities will know what is expected and when. The SDT recognized that because the characteristics and UFLS needs of regions are different, establishing one UFLS program is unrealistic; however, the standard does propose common performance characteristics that all UFLS programs must meet. This promotes consistency for the benefit of reliability across UFLS programs while not prescribing one program that would excessively restrict regions from designing UFLS programs that best fulfill their needs.				

A. Introduction

1. Title: **Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event**

2. Number: PRC-009-0

3. Purpose: Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. Applicability:

4.1. Transmission Owner required by its Regional Reliability Organization to own a UFLS program

4.2. Transmission Operator required by its Regional Reliability Organization to operate a UFLS program

4.3. Load-Serving Entity required by the Regional Reliability Organization to operate a UFLS program

4.4. Distribution Provider required by the Regional Reliability Organization to own or operate a UFLS program

5. Effective Date: April 1, 2005

B. Requirements

R1. The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:

R1.1. A description of the event including initiating conditions.

R1.2. A review of the UFLS set points and tripping times.

R1.3. A simulation of the event.

R1.4. A summary of the findings.

R2. The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.

C. Measures

M1. Each Transmission Owner's, Transmission Operator's, Load-Serving Entity's and Distribution Provider's documentation of the UFLS program performance following an underfrequency event includes all elements identified in Reliability Standard PRC-009-0_R1.

M2. Each Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operate a UFLS program, shall have evidence it provided documentation of the analysis of the UFLS program performance following an underfrequency event as specified in Reliability Standard PRC-009-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request 90 calendar days after the system event.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was incomplete in one or more elements in Reliability Standard PRC-009-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. Title: **Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organization's Underfrequency Load Shedding Program Requirements**

2. Number: PRC-007-0

3. Purpose: Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. Applicability:

4.1. Transmission Owner required by its Regional Reliability Organization to own a UFLS program

4.2. Transmission Operator required by its Regional Reliability Organization to operate a UFLS program

4.3. Distribution Provider required by its Regional Reliability Organization to own or operate a UFLS program

4.4. Load-Serving Entity required by its Regional Reliability Organization to operate a UFLS program

5. Effective Date: April 1, 2005

B. Requirements

R1. The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.

R2. The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.

R3. The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).

C. Measures

M1. Each Transmission Owner's and Distribution Provider's UFLS program shall be consistent with its associated Regional Reliability Organization's UFLS program requirements.

M2. Each Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program shall have evidence that it provided its associated Regional Reliability Organization and NERC with documentation of the UFLS program on request (30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The evaluation of the entity's UFLS program for consistency with its Regional Reliability Organization's UFLS program is incomplete or inconsistent in one or more requirements of Reliability Standard PRC-006-0_R1, but is consistent with the required amount of Load shedding.

2.2. Level 2: The amount of Load shedding is less than 95percent of the Regional requirement in any of the Load steps.

2.3. Level 3: The amount of Load shedding is less than 90percent of the Regional requirement in any of the Load steps.

2.4. Level 4: The evaluation of the entity's UFLS program for consistency with its Regional Reliability Organization's UFLS program was not provided or the amount of Load shedding is less than 85 percent of the Regional requirement on any of the Load steps.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

A. Introduction

1. Title: **Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs**

2. Number: PRC-006-0

3. Purpose: Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

4. Applicability:

4.1. Regional Reliability Organization

5. Effective Date: April 1, 2005

B. Requirements

R1. Each Regional Reliability Organization shall develop, coordinate, and document an UFLS program, which shall include the following:

R1.1. Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations.

R1.2. Design details shall include, but are not limited to:

R1.2.1. Frequency set points.

R1.2.2. Size of corresponding load shedding blocks (% of connected loads.)

R1.2.3. Intentional and total tripping time delays.

R1.2.4. Generation protection.

R1.2.5. Tie tripping schemes.

R1.2.6. Islanding schemes.

R1.2.7. Automatic load restoration schemes.

R1.2.8. Any other schemes that are part of or impact the UFLS programs.

R1.3. A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.

R1.4. Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to:

R1.4.1. A review of the frequency set points and timing, and

R1.4.2. Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation.

R2. The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).

R3. The Regional Reliability Organization shall provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization shall have documentation of the UFLS program and current UFLS database.

M2. The Regional Reliability Organization shall have evidence it provided documentation of its UFLS program and its database information to NERC as specified in Reliability Standard PRC-006-0_R2.

M3. The Regional Reliability Organization shall have evidence it provided documentation of its assessment of its UFLS program to NERC as specified in Reliability Standard PRC-006-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days) for the program, database, and results of assessments.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation demonstrating the coordination of the Regional Reliability Organization's UFLS program was incomplete in one of the elements in Reliability Standard PRC-006-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Documentation demonstrating the coordination of the Regional Reliability Organization's UFLS program was incomplete in two or more requirements or documentation demonstrating the coordination of the Regional Reliability Organization's UFLS program was not provided, or an assessment was not completed in the last five years.

E. **Regional Differences**

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for Underfrequency Load Shedding Project

Standards Involved

- PRC-006-1 Underfrequency Load Shedding
- EOP-003-2 – Load Shedding Plans
- PRC-006-0 — Development and Documentation of Regional UFLS Programs
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements
- PRC-009-0 — UFLS Performance Following an Underfrequency Event

Prerequisite Approvals

With one exception, there are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Under Frequency Load Shedding standard and any associated regional reliability standards can be implemented. Parts 4.1 through 4.6 of Requirement R4 of the Under Frequency Load Shedding standard shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

Proposed Effective Date

Compliance with the new version PRC-006-1 — Underfrequency Load Shedding reliability standard (Requirements R1 through R14 with the exception noted above for Requirement R4, Parts 4.1 through 4.6) is effective one year following the first day of the first calendar quarter after applicable regulatory approvals.

The one year phase-in for compliance is intended to provide Planning Coordinators sufficient time: 1) to develop, modify, or validate (to determine that the program meets performance characteristics) existing UFLS programs, and 2) to establish a schedule for implementation, or validate a schedule for completion of program revisions already in progress. Transmission Owners and Distribution Providers shall comply with the schedule determined by the Planning Coordinator but no sooner than the effective date of the standard.

Compliance with the revised EOP-003-2 — Load Shedding Plans reliability standard is effective one year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

Applicability

Certain requirements within the proposed standard are intended to apply only to entities that own or operate UFLS relays. These requirements would not apply to other entities. The drafting team has designated these entities that own or operate UFLS relays as “UFLS Entities.” They may include the following:

- Transmission Owners
- Distribution Providers

For decades underfrequency load shedding programs have been implemented by different entities depending on how the transmission system was constructed and owned. In some parts of the country, Distribution Providers accomplished this task, in others it was the Transmission Owners. Indeed, the set of standards intended to be replaced by this new standard allowed either of these registered entities, along with others in some cases, to accomplish the task of owning and operating UFLS relays. Because of this historical nature of the entities involved in the implementation of UFLS programs, and as listed in the applicability listed in the standards PRC-007-0 and PRC-009-0 that this standard is intended to replace, each of the functions listed above will have a role in implementing UFLS programs.

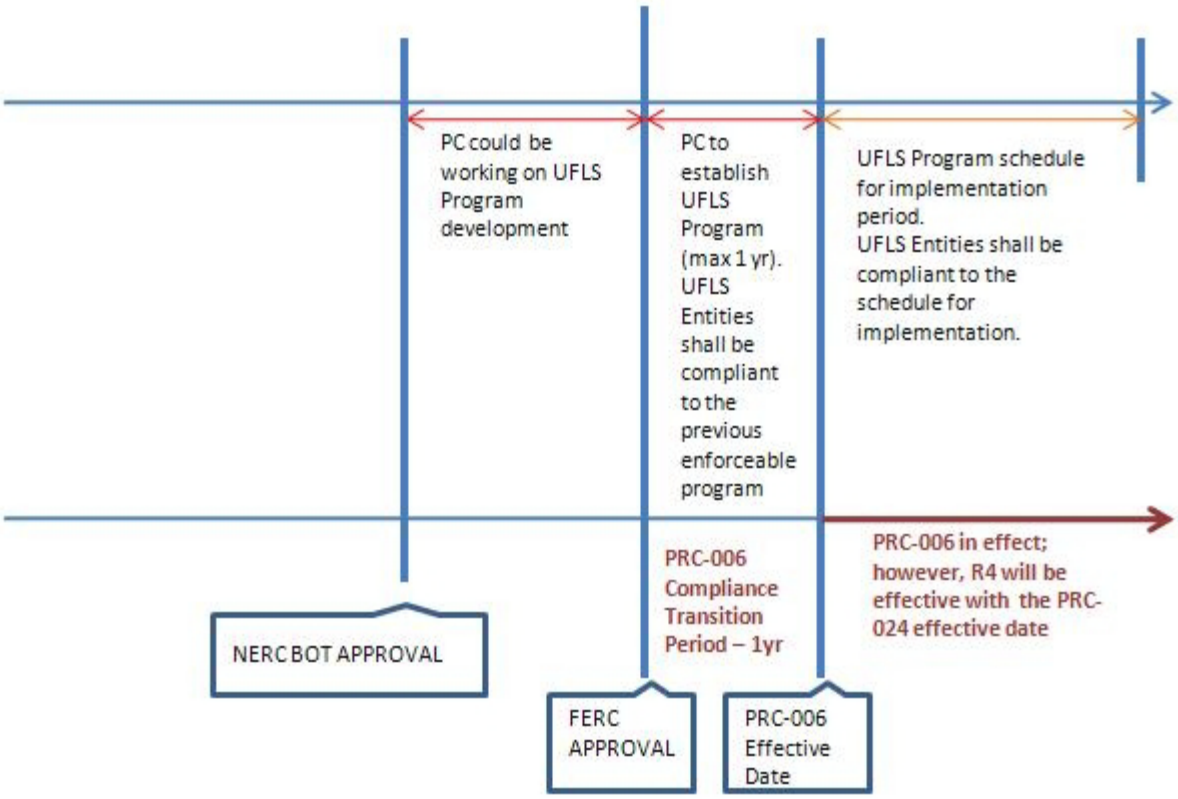
Retired Standards

The following standards will be retired when PRC-006-1 becomes effective:

- PRC-006-0 — Development and Documentation of Regional UFLS Programs will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements will be completely retired once PRC-006-1 becomes effective as specified above.
- PRC-009-0 — UFLS Performance Following an Underfrequency Event will be completely retired once PRC-006-1 becomes effective as specified above.

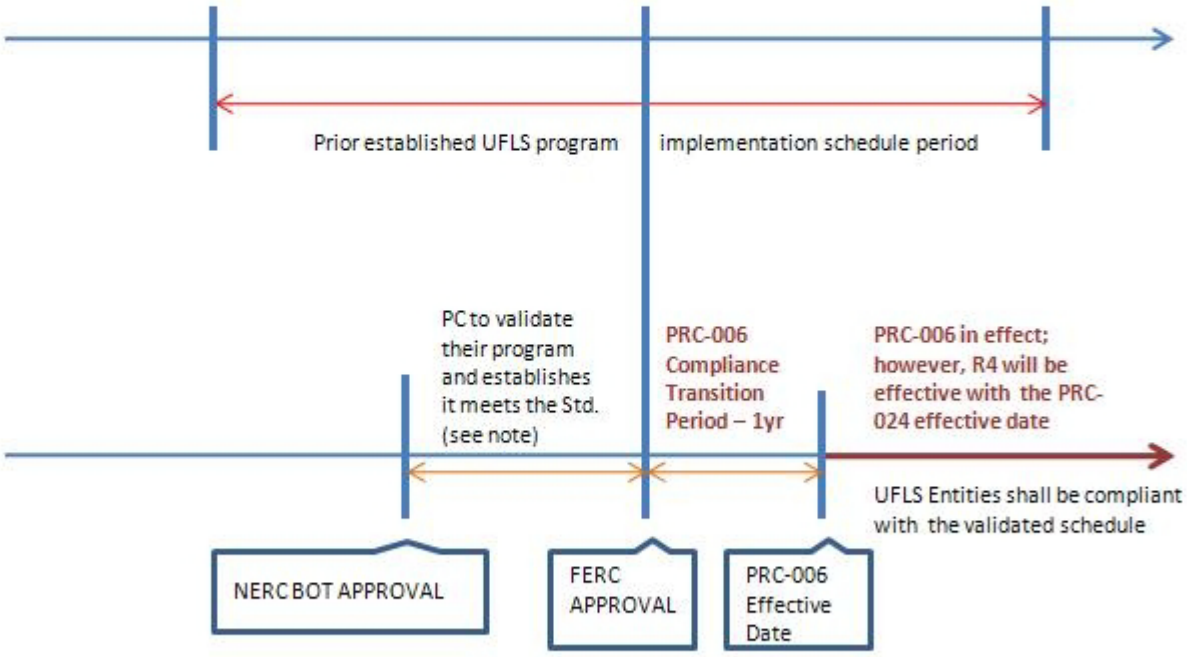
UFLS Timeline Example 1

(No Existing program)



UFLS Timeline Example 2

(Existing UFLS program)



Note: If the PC determines that their program is not valid to the standard, PC will need to follow Timeline Example 1.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Standards Committee approved the Supplemental SAR for posting on October 7, 2009 that expanded the SDT's scope to include EOP-003-1 but limiting that scope to only eliminating references to Under-frequency Load Shedding in EOP-003-1.
2. The Standards Drafting Team posted the standard for a third comment period June 11, 2010 – July 16, 2010.
3. The Standard Drafting Team conducted a pre-ballot review of the standard on June 11, 2010 – July 2, 2010
4. The Standard Drafting Team conducted an initial ballot of the standard and non-binding poll of the VRFs and VSLs on July 8, 2010 – July 17, 2010.
5. The Standard Drafting Team conducted a second ballot of the standard on July 24, 2010 – August 3, 2010.
6. The Standard Drafting Team conducted a successive ballot of the standard from September 24 – October 4, 2010.

Proposed Action Plan and Description of Current Draft:

This is the recirculation ballot period of the proposed standard.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Request BOT approval	November 3, 2010
2. File Standard with FERC	December, 2010

A. Introduction

1. Title: **Load Shedding Plans**

2. Number: EOP-003-2

3. Purpose: A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. Applicability:

4.1. Transmission Operators.

4.2. Balancing Authorities.

5. Effective Date: One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions

R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

M1. Each Transmission Operator that has or directs the deployment of undervoltage load shedding facilities, shall have and provide upon request, its automatic load shedding plans. (Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
R2	N/A	N/A	N/A	The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.
R3.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
R4.	N/A	N/A	N/A	The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.
R5.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
R7.	The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.
R8.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Modified R4, R5, R6 and associated VSLs for R2, R4, and R7to clarify that the requirements don’t apply to automatic underfrequency load shedding	Revised to eliminate redundancies with PRC-006-1

A. Introduction

1. **Title:** **Load Shedding Plans**

2. **Number:** EOP-003-12

3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

~~1. **Effective Date:** January 1, 2007~~

5. **Effective Date:** One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator ~~and Balancing Authority~~ shall establish plans for automatic load shedding for ~~underfrequency or~~ undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator ~~or Balancing Authority~~ shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: ~~frequency, rate of frequency decay,~~ voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator ~~and Balancing Authority~~ shall coordinate automatic undervoltage load shedding throughout their areas with ~~underfrequency isolation of generating units,~~ tripping of shunt capacitors, and other automatic actions that will occur under abnormal ~~frequency,~~ voltage, or power flow conditions~~.~~

R8. Each Transmission Operator or Balancing Authority shall have plans for operator ~~-~~controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

M1. Each Transmission Operator ~~and Balancing Authority~~ that has or directs the deployment of undervoltage ~~and/or underfrequency~~ load shedding facilities, shall have and provide upon request, its automatic load shedding plans~~.~~(. (Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring ~~and Reset Time Frame~~

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels of Non-Compliance:

1.1. Level 1: Not applicable.

1.2. Level 2: Not applicable.

1.3. Level 3: Not Applicable.

1.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

1.4.1 Does not have an automatic load shedding plan as specified in R2.

1.4.2 Does not have manual load shedding plans as specified in R8.

R#		Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.		N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
R2		N/A	N/A	N/A	The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requirement.
R3.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
R4.	N/A	N/A	N/A	The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.
R5.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.
R6.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7.	The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.
R8.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
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1	November 1, 2006	Adopted by Board of Trustees	Revised
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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on November 21, 2006.
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting Team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard, and posts for comments on April 15, 2009.
10. Standards Committee approved the Supplemental SAR for posting on October 7, 2009 that expanded the SDT's scope to include EOP-003-1 but limiting that scope to only eliminating references to Under-frequency Load Shedding in EOP-003-1.
11. The Standards Drafting Team posted the standard for a third comment period June 11, 2010 – July 16, 2010.
12. The Standard Drafting Team conducted a pre-ballot review of the standard on June 11, 2010 – July 2, 2010
13. The Standard Drafting Team conducted an initial ballot of the standard and non-binding poll of the VRFs and VSLs on July 8, 2010 – July 17, 2010.
14. The Standard Drafting Team conducted a second ballot of the standard on July 24, 2010 – August 3, 2010.
15. The Standard Drafting Team conducted a third ballot of the standard September 24-October 4, 2010.

Proposed Action Plan and Description of Current Draft:

This is the recirculation ballot period of the proposed standard.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Request BOT approval	November , 2010
2. File Standard with FERC	December, 2010

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-1

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.3 Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **(Proposed) Effective Date:**

   5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.

   5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

B. Requirements

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

R3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: Medium][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection

within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those

of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per

Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking

- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.

E. Regional Variances

E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E.A.3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

EA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

EA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

EA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

E.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

E.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.E.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

M.E.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
EA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
EA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3

E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

E.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2.1. Those islands selected by applying the criteria in Requirement E.B.1, and

E.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

EB.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

E.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

E.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

E.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

E.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

E.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

E.B.11.1. The performance of the UFLS equipment,

E.B.11.2 The effectiveness of the UFLS program

E.B.12. Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.E.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.

M.E.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.

M.E.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.

M.E.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.

M.E.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.

M.E.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands
E.B.2	N/A	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				regional review to serve as a basis for designing its UFLS program.
E.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
E.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	through E.B.4.7.	through E.B.4.7.	through E.B.4.7.	through E.B.4.7. OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2
E.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.	assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.
E.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

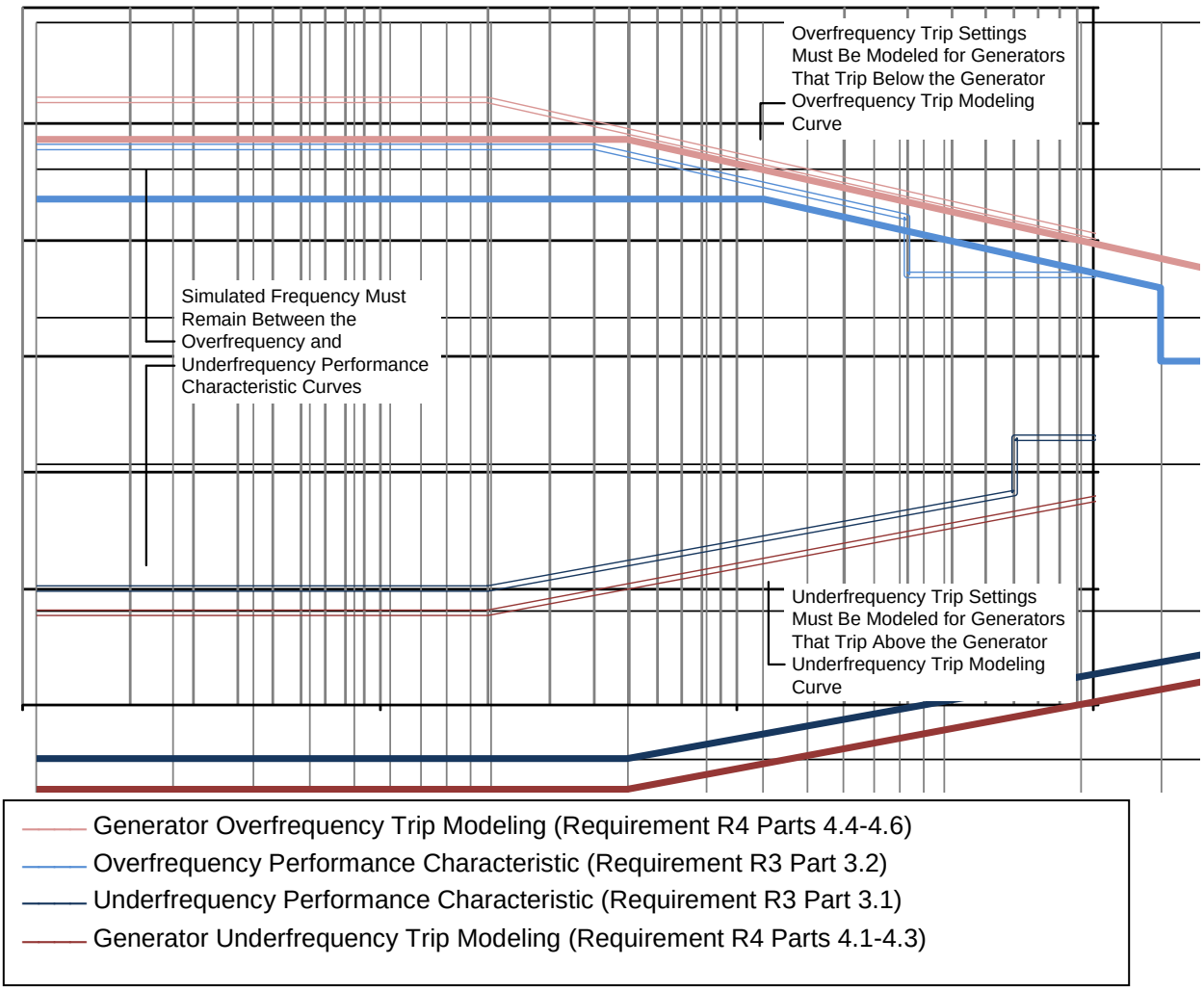
Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0	

PRC-006-1 – Attachment 1

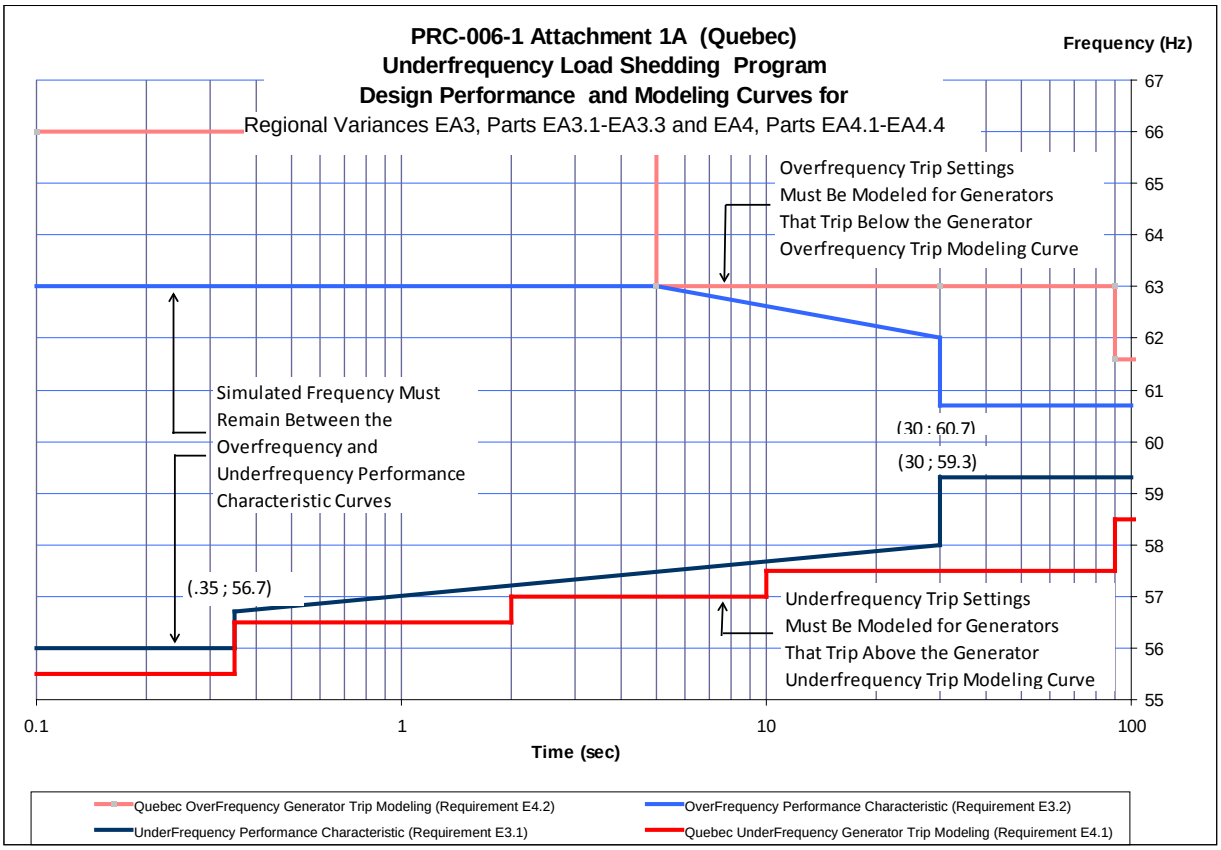
Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling		Underfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-1 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances EA3, Parts EA3.1-EA3.3 and EA4, Parts EA4.1-EA4.4
Frequency (Hz)
67
66
65
64
63
62
61
60
59
58
57
56
55
Overfrequency Trip Settings
Must Be Modeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(30 ; 60.7)
(30 ; 59.3)
(.35 ; 56.7)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip Modeling Curve
0.1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement E4.2)
OverFrequency Performance Characteristic (Requirement E3.2)
UnderFrequency Performance Characteristic (Requirement E3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement E4.1)

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on November 21, 2006.
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting Team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard, and posts for comments on April 15, 2009.
10. Standards Committee approved the Supplemental SAR for posting on October 7, 2009 that expanded the SDT's scope to include EOP-003-1 but limiting that scope to only eliminating references to Under-frequency Load Shedding in EOP-003-1.
11. The Standards Drafting Team posted the standard for a third comment period June 11, 2010 – July 16, 2010.
12. The Standard Drafting Team conducted a pre-ballot review of the standard on June 11, 2010 – July 2, 2010
13. The Standard Drafting Team conducted an initial ballot of the standard and non-binding poll of the VRFs and VSLs on July 8, 2010 – July 17, 2010.
14. The Standard Drafting Team conducted a second ballot of the standard on July 24, 2010 – August 3, 2010.
15. The Standard Drafting Team conducted a third ballot of the standard September 24-October 4, 2010.

Proposed Action Plan and Description of Current Draft:

This is the recirculation ballot period of the proposed standard.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Request BOT approval	November , 2010
2. File Standard with FERC	December, 2010

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-1

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.3 Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **(Proposed) Effective Date:**

   5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.

   5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

B. Requirements

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from R~~r~~egional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

R3. Each Planning Coordinator shall develop~~-~~ a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: Medium][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection

within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those

of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per

Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking

- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,-but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area .-
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.

E. Regional Variances

E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E.A.3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

EA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

EA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

EA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

E.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

E.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.E.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

M.E.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
EA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
EA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3

E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

E.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2.1. Those islands selected by applying the criteria in Requirement E.B.1, and

E.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

EB.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

E.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

E.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

E.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

E.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

E.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

E.B.11.1. The performance of the UFLS equipment,

E.B.11.2 The effectiveness of the UFLS program

E.B.12. Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.E.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.

M.E.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.

M.E.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.

M.E.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.

M.E.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.

M.E.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands
E.B.2	N/A	~~The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2~~ N/A	~~The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include two (2) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2~~ The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2	regional review to serve as a basis for designing its UFLS program.
E.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
E.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years ~~with the other Planning Coordinators in the WECC Regional Entity area~~ that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years ~~with the other Planning Coordinators in the WECC Regional Entity area~~ that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years ~~with the other Planning Coordinators in the WECC Regional Entity area~~ that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years ~~with the other Planning Coordinators in the WECC Regional Entity area~~ that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.	identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.	identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.	identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7. OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years ~~with the other Planning Coordinators in the WECC Regional Entity area~~ that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2
E.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation. OR

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.	The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.
E.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

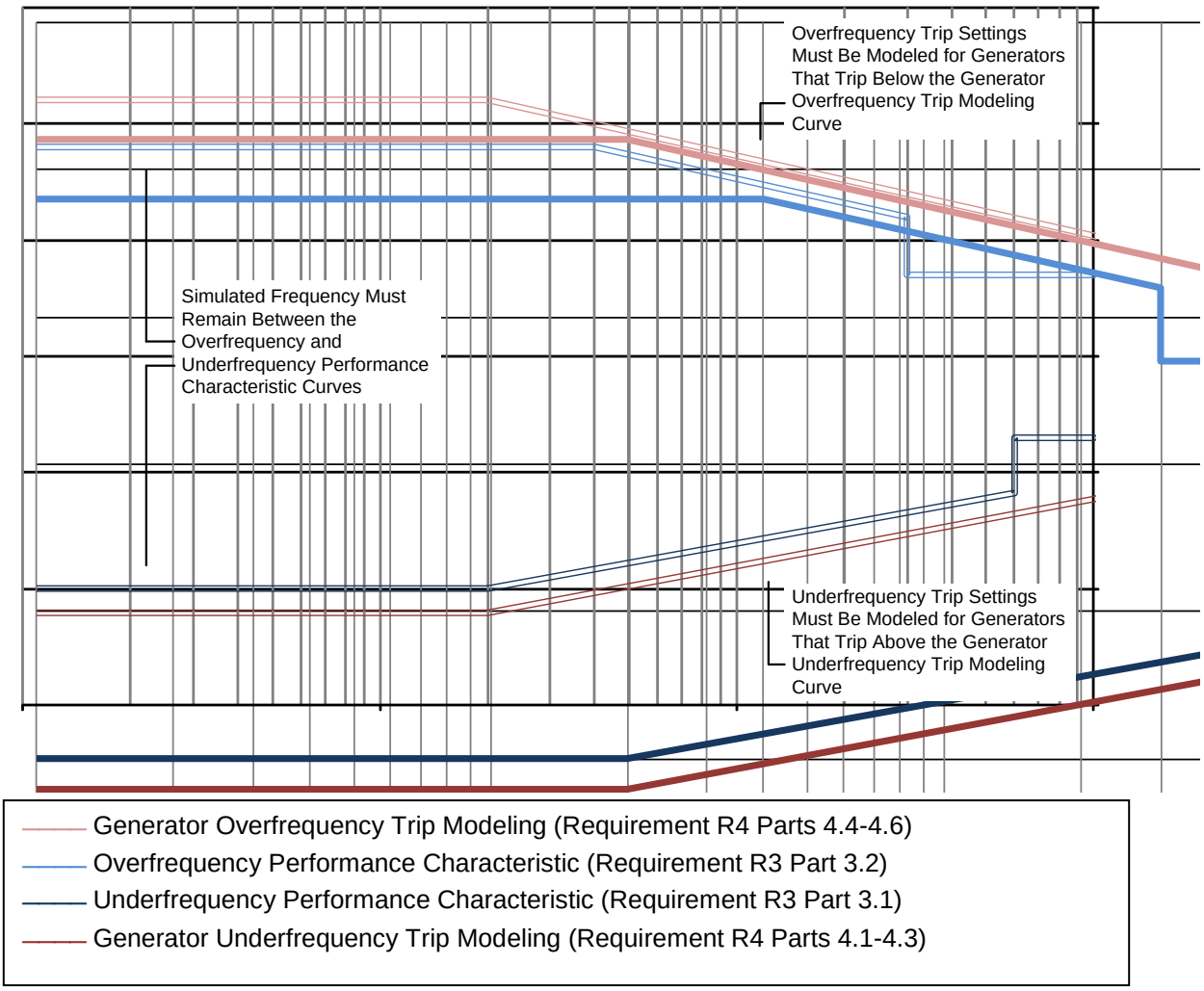
Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0	

PRC-006-1 – Attachment 1

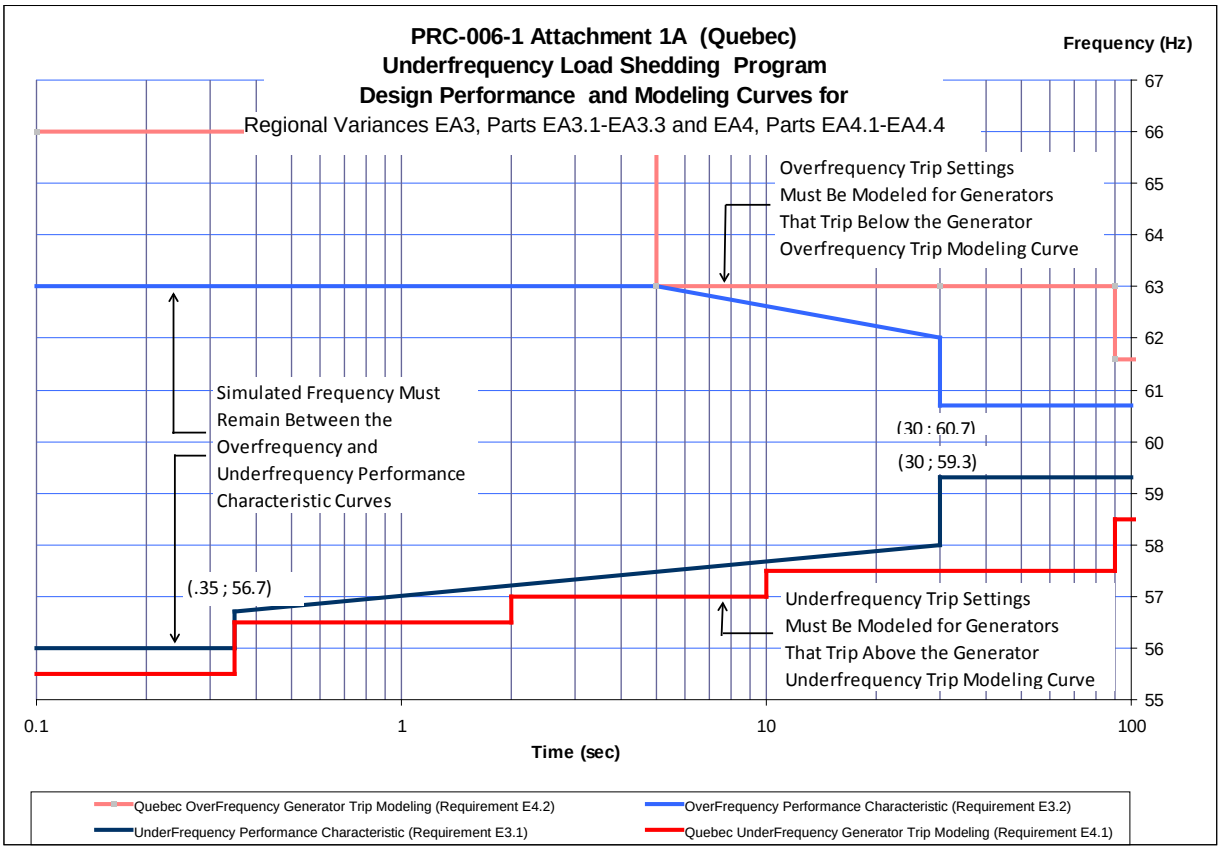
Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling		Underfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-1 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances EA3, Parts EA3.1-EA3.3 and EA4, Parts EA4.1-EA4.4
Frequency (Hz)
67
66
65
64
63
62
61
60
59
58
57
56
55
Overfrequency Trip Settings
Must Be Modeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(30 ; 60.7)
(30 ; 59.3)
(.35 ; 56.7)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip Modeling Curve
0.1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement E4.2)
OverFrequency Performance Characteristic (Requirement E3.2)
UnderFrequency Performance Characteristic (Requirement E3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement E4.1)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Recirculation Ballot Open
October 18-28, 2010

Available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2007-01 Underfrequency Load Shedding

A recirculation ballot period is open through **8 p.m. Eastern on October 28, 2010**.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Ballot Process

The Standards Committee encourages all members of the ballot pool to review the consideration of comments submitted during the last ballot window. In the recirculation ballot, votes are counted by exception only. If a ballot pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot
- Vote in the second ballot even if they did not vote on the first ballot
- Take no action if they do not want to change their original vote

Additional Information

For a recirculation ballot, the Standard Processes Manual allows drafting teams to make changes with a goal of improving the quality of a standard, provided those changes do not alter the applicability or scope of the proposed standard. The UFLS Standard Drafting Team made the following minor edits to PRC-006-1 following the last ballot based on stakeholder comments:

- Requirement R2, Part 2.3 – changed, "regional boundaries" to "Regional Entity area boundaries" for clarity
- VSLs for Requirement R3 – added the phrase, "where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)" to the Moderate, High, and Severe VSLs for closer alignment with the requirement
- VSLs for Requirement E.B.2 and E.B.4 – updated to more accurately align with the associated requirements

A redline version of the standard showing the above changes has been posted for stakeholder review

Note that PRC-006-1 reflects the merging of the following standards into a single standard, making it impractical to post a "redline" of proposed PRC-006-1 that shows the changes to the last balloted version of the standard. For stakeholders who want to see the last approved versions of PRC-006-0, PRC-007-0 and PRC-009-0, these have been posted on the UFLS project page for easy reference.

- PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
- PRC-007 — Assuring Consistency with Regional UFLS Programs
- PRC-009 — UFLS Performance Following an Underfrequency Event

Next Steps

Voting results will be posted and announced after the ballot window closes. If approved, the standards, Violation Risk Factors, Violation Severity Levels and associated implementation plan will be submitted to the Board of Trustees.

Project Background

Major objectives:

1. Ensure UFLS programs are developed to provide an appropriate level of reliability (not least common denominator).
2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.
3. Address the issues raised by FERC Order 693 and other applicable orders.
4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.
5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

Further details are available on the project page:
http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Ballot Results

Ballot Name:	Project 2007-01: Underfrequency Load Shedding_sb_rc
Ballot Period:	10/18/2010 - 10/28/2010
Ballot Type:	recirculation
Total # Votes:	283
Total Ballot Pool:	315
Quorum:	**89.84 % The Quorum has been reached**
Weighted Segment Vote:	84.67 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	89	1	68	0.861	11	0.139	7	3
2 - Segment 2.	10	0.8	7	0.7	1	0.1	0	2
3 - Segment 3.	76	1	53	0.841	10	0.159	4	9
4 - Segment 4.	26	1	18	0.818	4	0.182	3	1
5 - Segment 5.	57	1	32	0.78	9	0.22	8	8
6 - Segment 6.	36	1	21	0.75	7	0.25	2	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.5	4	0.4	1	0.1	1	1
9 - Segment 9.	7	0.6	6	0.6	0	0	0	1
10 - Segment 10.	7	0.6	6	0.6	0	0	0	1
Totals	**315**	**7.5**	**215**	**6.35**	**43**	**1.15**	**25**	**32**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Affirmative	
1	Baltimore Gas & Electric Company	John J. Moraski	Abstain	

1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Negative	View
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Commonwealth Edison Co.	Daniel Brotzman	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Negative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar	Affirmative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lake Worth Utilities	Walt Gill	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	Metropolitan Water District of Southern California	Ernest Hahn	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Affirmative	View
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Douglas G Peterchuck	Negative	View
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Mark Sampson		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	View
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	

1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Abstain	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Affirmative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	View
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	Alberta Electric System Operator	Jason L. Murray		
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Transmission Corporation	Faramarz Amjadi		
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana	Affirmative	View
3	Arizona Public Service Co.	Thomas R. Glock		
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson		
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	View
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Negative	View
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Los Angeles Department of Water & Power	Kenneth Silver		

3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	Manitoba Hydro	Greg C Parent	Negative	View
3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	New York Power Authority	Marilyn Brown		
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	North Carolina Municipal Power Agency #1	Denise Roeder	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	OTP Wholesale Marketing	Bradley Tollerson	Negative	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	View
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Mississippi Electric Power Association	Gary Hutson		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Springfield Utility Board	Jeff Nelson	Abstain	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power - Ohio	Kevin Koloini	Negative	
4	American Public Power Association	Allen Mosher	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	View
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
4	Y-W Electric Association, Inc.	James A Ziebarth	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Affirmative	

5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith		
5	East Kentucky Power Coop.	Stephen Ricker	Negative	View
5	Entergy Corporation	Stanley M Jaskot	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Green Country Energy	Greg Froehling	Abstain	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens		
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Negative	
5	Otter Tail Power Company	Stacie Hebert	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Mark A Heimbach		
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	View
5	Reedy Creek Energy Services	Bernie Budnik		
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	South Mississippi Electric Power Association	Jerry W Johnson		
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Cleco Power LLC	Matthew D Cripps	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View

6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Abstain	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Negative	
6	OTP Wholesale Marketing	Bruce Glorvigen	Negative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	RRI Energy	Trent Carlson		
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Abstain	View
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	View
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Abstain	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	North Carolina Utilities Commission	Kimberly J. Jones	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement
Recirculation Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2007-01 Underfrequency Load Shedding
The recirculation ballot for Project 2007-01 - Underfrequency Load Shedding ended October 28, 2010.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 89.84 %
Approval: 84.67 %

The ballot pool approved PRC-006-1 – Automatic Underfrequency Load Shedding and approved EOP-003-2 – Load Shedding Plans and the associated implementation plan; and approved retirement of the following three standards:

- PRC-006 — Development and Documentation of Regional Reliability Organizations' Underfrequency Load Shedding Programs
- PRC-007 — Assuring Consistency with Regional UFLS Programs
- PRC-009 — UFLS Performance Following an Underfrequency Event

Ballot criteria details are listed at the end of the announcement.

Next Steps
The two new standards and their associated implementation plan; and the three standards that were approved for retirement will be submitted to the NERC Board of Trustees for approval, with the proposed Violation Risk Factors and Violation Severity Levels that were reviewed by stakeholders during the non-binding poll conducted with the initial ballot for PRC-006-1.

Project Background
Major objectives:

1. Ensure UFLS programs are developed to provide an appropriate level of reliability (not least common denominator).

2. Ensure that the standard is enforceable with clearly defined requirements and unambiguous language.

3. Address the issues raised by FERC Order 693 and other applicable orders.

4. Address the issues raised in the original Standards Authorization Request (SAR) for this project.

5. Address coordination between underfrequency load shedding and generator trip settings during frequency excursions.

Further details are available on the project page:

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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