UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RD13-_____**

JOINT PETITION FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD PRC-006-SPP-01 (UNDER FREQUENCY LOAD SHEDDING)

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The North American Electric Reliability Corporation ("NERC")[1] hereby requests Federal Energy Regulatory Commission ("Commission") approval, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of the Commission's regulations,[3] of proposed regional Reliability Standard PRC-006-SPP-01 (Automatic Underfrequency Load Shedding) developed by NERC and the Southwest Power Pool Regional Entity ("SPP RE"),[4] a division of Southwest Power Pool, Inc.[5] Proposed regional Reliability Standard PRC-006-SPP-01 was approved by the NERC Board of Trustees on November 7, 2012. NERC requests that the Commission approve proposed regional Reliability Standard PRC-006-SPP-01 (**Exhibit A**) and find that the proposed regional Reliability Standard is just, reasonable, not unduly discriminatory

1 NERC has been certified by the Commission as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA. *See N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

2 16 U.S.C. § 824o (2006).

3 18 C.F.R. § 39.5 (2012).

4 As the Regional Entity who developed proposed regional Reliability Standard PRC-006-SPP-01, SPP RE joins and supports NERC's petition, thereby making SPP RE a party in this proceeding.

5 The Commission originally approved delegation agreements between NERC and SPP RE (and between NERC and seven other Regional Entities) in an order issued April 19, 2007. *Order Accepting ERO Compliance Filing, Accepting ERO/Regional Entity Delegation Agreements, and Accepting Regional Entity 2007 Business Plans*, 119 FERC ¶ 61,060 (2007), *order on reh'g*, 120 FERC ¶ 61,260 (2007). In subsequent orders, the Commission has approved revisions to the SPP RE regional delegation agreement. *Order Addressing Revised Delegation Agreements*, 122 FERC ¶ 61,245 (2008); *Order Accepting Compliance Filings, Subject to Conditions*, 125 FERC ¶ 61,330 (2008); *Order Conditionally Accepting Compliance Monitoring and Enforcement Program Agreements and Revised Delegation Agreements, and Ordering Compliance Filing*, 123 FERC ¶ 61,024, *order on reh'g and accepting filing* 133 FERC ¶ 61,190 (2010); *N. Am. Elec. Reliability Corp.*, Docket Nos. RR10-7-002 and RR10-11-00 (Mar. 1, 2011) (unpublished letter order).

or preferential, and in the public interest. NERC also requests approval of the associated Violation Risk Factors ("VRFs")[6] and Violation Severity Levels ("VSLs") (**Exhibit A**) and the implementation plan (**Exhibit C**). In the implementation plan, SPP RE states that Requirements R4, R5, and R6 shall become effective the first day of the first calendar quarter one year after regulatory approval. The one year phase in for compliance is needed for the Planning Coordinator to perform the studies necessary to assess the effectiveness of the UFLS program. The remaining Requirements shall become effective the first day of the first calendar quarter three years after regulatory approval. The additional two year phase-in for compliance is needed for necessary changes to be made to the existing UFLS schemes.

As required by Section 39.5(a)[7] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed regional Reliability Standard, a summary of the development proceedings conducted by NERC and SPP RE for proposed PRC-006-SPP-01, and a demonstration that the proposed regional Reliability Standard meets the criteria identified by the Commission in Order No. 672.[8] Upon approval, this proposed regional Standard will only be effective within the SPP RE footprint.

I. <u>EXECUTIVE SUMMARY</u>

The purpose of PRC-006-SPP-01 is to develop, coordinate, and document requirements for automatic underfrequency load shedding ("UFLS") programs to arrest declining frequency and assist recovery of frequency following underfrequency events, in coordination with the continent-wide UFLS Reliability Standard, PRC-006-1. UFLS requirements have been in place

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[6] Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, available at http://www.nerc.com/files/Glossary_of_Terms.pdf.

[7] 18 C.F.R. § 39.5(a) (2012).

[8] The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

within SPP RE footprint prior to the development of the regional Reliability Standard and have been reflected into the regional Reliability Standard.[9]

A region-wide and fully coordinated single set of UFLS requirements is of benefit to achieving an effective and efficient UFLS program. Operating experience within SPP RE has confirmed this conclusion. Regional UFLS programs, such as the UFLS scheme in SPP RE, serve "as a last resort to preserve the Bulk-Power System during a major system failure that could cause system frequency to collapse."[10] Proposed regional Reliability Standard PRC-006-SPP-01 adds specificity not contained in continent-wide Standard PRC-006-1 with respect to the development and implementation of a UFLS program in the SPP RE footprint. This petition is the first request by NERC for Commission-approval of this proposed regional Reliability Standard and represents the first regional Reliability Standard developed by SPP RE. The proposed regional Reliability Standard will be in effect only for applicable registered entities within the SPP RE region.

II. <u>NOTICES AND COMMUNICATIONS</u>

Notices and communications with respect to this filing may be addressed to the following:[11]

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9 *See* Section 7.3 of the SPP Criteria ("SPP UFLS Criteria"), *available at* http://www.spp.org/publications/SPP%20Criteria%20and%20Appendices%20January%202012.pdf.

10 *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1476, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

11 Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2012), to allow the inclusion of more than two persons on the service list in this proceeding.

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III. BACKGROUND

By enacting the Energy Policy Act of 2005,[12] Congress entrusted the Commission 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 Commission approval. Section 215(b)(1)[13] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[14] of the

[12] 16 U.S.C. § 824o (2006).
[13] *Id.* § 824(b)(1).
[14] *Id.* § 824o(d)(5).

FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[15] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve standards that protect the reliability of the Bulk-Power System and to ensure that such standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. A Reliability Standard proposed by a Regional Entity must meet the same standard that NERC's Reliability Standards must meet, *i.e.*, the regional Reliability Standard must be shown to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[16] If the regional Reliability Standard is proposed by a Regional Entity organized on an Interconnection-wide basis, to be applicable on an Interconnection-wide basis, then NERC must rebuttably presume that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[17]

Pursuant to Section 215(d)(2) of the FPA[18] and Section 39.5(c)(1)-(2)[19] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard and to the technical expertise of a Regional Entity organized on an Interconnection-wide basis with respect to a Reliability Standard to be applicable within that Interconnection. In Order No. 672, the Commission noted that:

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[15] 18 C.F.R. § 39.5(a) (2012).
[16] 16 U.S.C. § 824o(d)(2); 18 C.F.R. §39.5(a).
[17] 16 U.S.C. § 824o(d)(3); 18 C.F.R. §39.5(b).
[18] 16 U.S.C. § 824o(d)(2).
[19] 18 C.F.R. § 39.5(c)(1)(2).

> As a general matter, we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.[20]

A regional difference generally takes one of two forms: (1) a regional variance may be included in a continent-wide Reliability Standard, which achieves the reliability objective of the continent-wide standard's requirement(s) in an alternate way than specified in a given Requirement in the continent-wide standard or (2) a separate regional Reliability Standard may be developed, which adds one or more Requirements without altering any continent-wide Requirements that are applicable to entities in the region.[21] Proposed regional Reliability Standard PRC-006-SPP-01 is a separate proposed regional Reliability Standard, which adds one or more Requirements without altering the continent-wide Requirements in PRC-006. As discussed in the *Southwest Power Pool Regional Entity Standards Development Process Manual*, the regional Reliability Standards for SPP RE are developed in a transparent, inclusive, open, and balanced process with reasonable notice and opportunity for public comment.[22]

IV. <u>JUSTIFICATION FOR APPROVAL</u>

This section discusses the history of proposed PRC-006-SPP-01 and the need for the proposed regional Reliability Standard. It also presents the technical basis and content of the proposed Reliability Standard, including an explanation of the Requirements. This section also

[20] Order No. 672 at P 291.
[21] *See* NERC, *Whitepaper to Provide Guidance on Regional Standards and Variances*, May 17, 2012, available at http://www.nerc.com/docs/sac/rsg/Whitepaper%20on%20Regional%20Standards%20and%20Variances%20final.pdf.
[22] The *Southwest Power Pool Regional Entity Standard Development Process Manual* is available at http://www.spp.org/publications/SPP%20RE%20Standards%20Development%20Process%20Manual.pdf

explains certain issues raised during the development of proposed regional Reliability Standard and the responses provided by SPP RE. NERC and SPP RE request Commission approval of proposed regional Reliability Standard PRC-006-SPP-01, including its implementation plan and associated VRFs and VSLs. As discussed in **Exhibit B**, proposed regional Reliability Standard PRC-006-SPP-01 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The complete development record for the proposed Regional Reliability Standard is provided in **Exhibits E and F** and includes the development and approval process, comments received during the comment periods, responses to those comments, ballot information, and NERC's evaluation of the proposed Standard.

A. <u>History of the PRC-006-SPP-01and Need for a Regional Reliability Standard</u>

On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC.[23] The Commission neither approved nor remanded Reliability Standard PRC-006-0,[24] which required Regional Reliability Organizations to develop, coordinate, document, and assess UFLS program design and effectiveness at least every five years. The Commission did not approve the proposed Reliability Standard because the regional procedures had not been submitted, and the Commission held that it would not propose to approve or remand PRC-006-0 until the ERO submitted the additional information.[25]

In 2007, SPP RE began work on PRC-006-SPP-01. NERC also began revising its continent-wide UFLS Reliability Standard, which was approved by the Commission on May 7,

[23] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[24] *Id.* P 1479.
[25] *Id.* PP 1477, 1479.

2012 in Order No. 763.[26] Proposed PRC-006-SPP-01 has been developed to effectively use the proven high performance characteristics of the existing SPP UFLS program and refine its requirements and coordination procedures.

On December 22, 2010, Powertech Labs, Inc. submitted a technical assessment of the performance of SPP's UFLS scheme as part of compliance requirements for UFLS programs as defined by NERC's then-effective UFLS Reliability Standards and SPP's existing UFLS criteria ("SPP UFLS Assessment").[27] In the SPP UFLS Assessment, the UFLS relay data submitted by SPP members was reviewed and the SPP power system was studied under a number of scenarios with varying degree of mismatches between load and generation to evaluate performance of the UFLS scheme. Overall, it was concluded that SPP's UFLS scheme complies with the NERC UFLS Requirements and the SPP UFLS Criteria. The SPP UFLS Assessment was used as an input to the proposed regional Reliability Standard.

B. <u>Basis and Purpose of Proposed PRC-006-SPP-01</u>

1. <u>Need for a Regional Reliability Standard in the SPP Region</u>

PRC-006-SPP-01 is designed to work in conjunction with Reliability Standard PRC-006-1 to effectively mitigate the consequences of an underfrequency event while creating a necessary, region-wide, and fully coordinated single set of UFLS requirements to create an effective and efficient UFLS program within the SPP RE footprint. The regional Standard approach would require all applicable SPP RE registered entities in the SPP RE footprint to comply with the proposed PRC-006-SPP-01. With only the continent-wide Reliability Standard PRC-006-1 in place, only those entities for which the SPP Regional Transmission Organization

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[26] *See Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Order No. 763, 139 FERC ¶ 61,098 (2012) (approving Reliability Standards PRC-006-1 (Automatic Underfrequency Load Shedding) and EOP-003-2 (Load Shedding Plans)).

[27] *See* **Exhibit I**.

is the Planning Coordinator are accountable to the UFLS program. Non-SPP members that are in the SPP RE footprint would not be held accountable to the UFLS program and, thus, would be required to develop their own or have another Planning Coordinator include them in its UFLS program.

2. <u>Explanation of Requirements in PRC-006-SPP-01</u>

Proposed PRC-006-SPP-01 applies to the Planning Coordinator, Generator Owners, and "UFLS entities", which is defined in the applicability section to include "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."[28] The applicability section also identifies that such UFLS entities may include Transmission Owners and Distribution Providers.[29] The proposed regional Standard includes nine Requirements summarized as follows:

Requirement R1 requires each UFLS entity that has a total forecasted peak load greater than or equal to 100 MW to develop and implement an automatic UFLS program that meets specific sub-Requirements, including a specific minimum and maximum load shedding percentage expressed as percentage of forecasted peak Load at each of three UFLS steps. The current UFLS program includes three separate UFLS steps with a minimum load shedding percentage of 10%, 20%, and 30%, cumulatively, for each of the three steps. These have remained unchanged from the SPP UFLS Criteria. The maximum load shedding percentages in steps 1 and 2 of the SPP Criteria were increased from 15% and 30%, respectively, to 25% and 35%, allowing more flexibility for those steps. The SPP UFLS Assessment shows that the increase in the upper limit of the steps did not compromise the reliability of the system, yet it

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[28] Exhibit A, PRC-006-SPP-01 at section 4.2

[29] *Id.* at section 4.2.1 and 4.2.2.

allows the members for flexibility when determining where to set the relay points of the UFLS relays.

Requirement R2 requires each UFLS entity that has a total forecasted peak load less than 100 MW to develop and implement an automatic UFLS program that meets specific sub-Requirements, including a minimum accumulated load relief of at least 30% of the forecasted peak load. Requirement R2 also requires a UFLS program to have a minimum of one UFLS step with the frequency set point as assigned by the Planning Coordinator. In drafting Requirement R2, the standard drafting team realized that some small UFLS entities may experience difficulty in achieving more than one UFLS step due to a smaller arrangement of loads and meeting the tolerances set forth in the load shedding table of Requirement R1.1. The basis for selecting 100 MW as the threshold came from the use of this same value in other regional UFLS standards[30] and a reasonable judgment that the total forecasted load served by smaller electric utilities is less than 100 MW. Requirement R2 was structured to accommodate these small entities and its inclusion within this proposed regional Standard indicates the importance of having all entities participate in the UFLS program in the SPP RE footprint.

Requirement R3 allows UFLS entities to elect to implement underfrequency islanding schemes following operation of all three underfrequency steps should the frequency continue to fall to 58.5 Hz or below. The standard drafting team included a time delay on initiation of islanding for frequencies slightly below the third step of load shedding to allow time for system recovery and to accommodate some frequency overshoot. The technical assessment conducted by Powertech showed that frequency excursions between 58.5 and 58.0 Hz would recover in less than 2 seconds. Therefore, having a 2 second time delay may avoid islanding. For islanding schemes designed to operate below 58.0 Hz, no time delay is required.

30 *See, e.g.*, SERC and NPCC??

Requirement R4 obligates the Planning Coordinator to perform and document a UFLS technical assessment within one year after performance characteristic changes to PRC-006 or PRC-006-SPP-01 are identified, or after changes to the boundaries of a specified island are identified. The standard drafting team included this Requirement because following these changes it is imperative to perform a new assessment to ensure UFLS program effectiveness.

Requirement R5 is a data reporting Requirement and requires UFLS entities to report certain data to the Planning Coordinator necessary to model the UFLS program. **Requirement R6** similarly requires the Generator Owner to report certain data to the Planning Coordinator to provide for improved modeling for UFLS technical assessments, performing routine UFLS studies, and post-event analysis. This data will enable the Planning Coordinator to evaluate whether the generator can meet Requirement R7 and determine if additional load shedding is required on the part of the UFLS entities. The data includes: location of underfrequency and overfrequency equipment, trip frequency(s) for each location, total relay operating time of each location, breaker operating time of each location, and MW of generation shed at each location. Improved technical assessments assists in protecting the reliability of the Bulk-Power System because there is a more accurate picture of what is needed to prevent Bulk-Power System frequency decline during UFLS events.

Requirement R7 requires Generator Owners to verify that their generating unit(s) will not trip above the generator underfrequency curve (*see* Attachment 1 of proposed PRC-006-SPP-01) and will not trip below the generator overfrequency curve (*see* Attachment 2 of proposed PRC-006-SPP-01) as a result of the frequency protective relay settings. To effectively study and evaluate the performance of the UFLS system, the generator relay protection trip values must be known and are critical to evaluating the performance of the SPP UFLS program. The goal is to balance the generation and load so a total collapse of the SPP system does not occur, therefore, protecting the Bulk Power System. For generating units with operating characteristics that limit the unit's ability to perform in accordance with Requirement R7, sub-Requirement R7.1 requires Generator Owners to provide the Planning Coordinator with technical evidence demonstrating that the Generator Owner's unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings.

Requirement R8 requires the Planning Coordinator to verify the Generator Owner's technical justification for not being able to operate based upon the Attachment 1 and 2 curves in PRC-006-SPP-01 and to review the consequences to the UFLS program performance for the loss of the additional generation after the initiation of an underfrequency event. The Requirement also provides a mechanism for the Planning Coordinator to resolve the detrimental effects of the loss of this additional generation if the Planning Coordinator determines that the performance of the UFLS program is degraded.

Requirement R9 requires the Generator Owners or other UFLS Entity(s) to implement supplementary shedding of Load required by the Planning Coordinator as defined in PRC-006-SPP-01 R8.1.1. The intent of this requirement is to prevent blackouts caused by early removal of generating units from the system. In a real time load shedding event, if the UFLS program is degraded in accordance with R8.1.1, removal of the unit would make the system worse. The supplementary shedding of load is critical to bring stability to the system and protect the reliability of the Bulk-Power System.

3. <u>Additional Stringency in the Regional Reliability Standard</u>

The proposed regional Reliability Standard is more stringent than the continent-wide Reliability Standard PRC-006 since it adds specificity not contained in PRC-006 for development and implementation of a UFLS scheme in the SPP RE footprint that effectively mitigates the consequences of an underfrequency event. This additional specificity is needed to arrest declining frequency and assist recovery of frequency following underfrequency events in the SPP RE footprint. For example, proposed PRC-006-SPP-01 includes Generator Owners as applicable entities. By requiring Generator Owners to report to the Planning Coordinator, there is a broader picture to clarify that an underfrequency event occurs because of a mismatch between generation and load. If generators trip because of an underfrequency event, then more load has to be shed than was expected. Generator Owners are included as applicable entities in the proposed Standard to make sure that the generators do not trip before the system has had a chance to recover after load is shed, thereby ensuring reliable operations of the Bulk-Power System.

Proposed PRC-006-SPP-01 also includes a stricter imbalance scenario of 30% than Reliability Standard PRC-006-1. PRC-006-1 requires Planning Coordinators to plan for an imbalance of 25%, while Requirement R1 of PRC-006-SPP-01 contains a greater imbalance scenario of 30%. Proposed PRC-006-SPP-01 also contains more detailed data submittal Requirements (*see* Requirements R5 and R6), which provide critical UFLS data to the Planning Coordinator for modeling the UFLS program. Finally, the proposed regional Reliability Standard specifies UFLS steps not contained in Reliability Standard PRC-006-1, such as three separate load shedding steps of 10% at each of 59.3, 59.0, and58.7 Hz.

In addition to the increased stringency compared to Reliability Standard PRC-006-1, proposed PRC-006-SPP-01 improves upon the current SPP UFLS Criteria. For example, the regional Reliability Standard was written to eliminate the need for waivers, which currently exist in the SPP UFLS Criteria. The SPP UFLS Criteria currently states that load that the member will shed is the "one-minute average of the member's load prior to the first underfrequency relay action taken at 59.3 Hz." This load shed can occur "at any given time", which creates a need for waivers in situations where the size of the member and the fluctuation of the load did not allow for the member to hit the 5% load shed window. Waivers are needed to meet the percentage of load shedding per step and SPP members could dynamically arm and disarm UFLS relays to achieve the required load shedding totals. The regional Reliability Standard was written as a planning standard to resolve this need for waivers, instead opting to use the shedding of each member's forecasted peak load. Measuring UFLS program performance based on the entity's planning values and not the one-minute average of the entity's load prior to the first underfrequency relay action eliminates the need to obtain waivers to meet the percentage of load shedding per UFLS step. The dynamic arming and disarming necessary under the SPP UFLS Criteria should not be necessary for a planning standard because load shedding is based on each SPP RE member's forecasted peak load.

C. Enforceability of Proposed PRC-006-SPP-01

Proposed PRC-006-SPP-01 contains Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. These Measures help provide clarity regarding how the Requirements will be enforced, and ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[31] The proposed regional Reliability Standard also contains both VRFs and VSLs assigned to each Requirement in the proposed Standard. The VRFs and VSLs for this

[31] 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.").

proposed Standard were developed and reviewed for consistency with NERC and Commission guidelines.[32] Analysis of the assigned VRFs and VSLs to this Standard is included in **Exhibit G**.

V. SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

The proposed PRC-006-SPP-01 regional Reliability Standard was developed using NERC's and SPP RE's Commission-approved, open and fair standard development processes and each was administered in a proper manner. The complete development record for PRC-006-SPP-01, including both NERC's and SPP RE's process, has been submitted as **Exhibits E and F**.

SPP RE posted the original draft regional Reliability Standard PRC-006-SPP-01 for initial industry comment on March 31, 2009. A second, third and fourth draft of the proposed regional Reliability Standard were posted for comment on August 31, 2009, March 29, 2010, and December 8, 2010 respectively. With each posting, SPP RE provided a response to the comments received. A fifth draft was posted for comment on January 18, 2011. The first ballot was conducted on February 3, 2011 on the fifth draft of the proposed regional Reliability Standard. The ballot failed with a weighted affirmative vote of 62%, falling short of the 66.7% necessary for approval. SPP RE posted a sixth draft for comment on June 10, 2011 and a seventh draft on September 30, 2011. The seventh draft was posted for voting October 15, 2011. The proposed regional Standard passed with an affirmative vote of 76%. On July 30, 2012, the SPP RE Board of Trustees unanimously approved PRC-006-SPP-01 for submittal to NERC.

On August 13, 2012, SPP RE submitted the proposed Regional Reliability Standard for evaluation by NERC in accordance with NERC's Rules of Procedure and Regional Reliability

[32] *See Order on Violation Risk Factors*, 119 FERC ¶ 61,145 (2007) and *Order on Violation Severity Levels Proposed by the Electric Reliability Organization*, 123 FERC ¶ 61,284 (2008).

Standards Evaluation Procedure that was approved by NERC's Regional Reliability Standards Working Group. NERC provided its evaluation of proposed PRC-006-SPP-01 and in this report, NERC provided minor formatting and wording suggestions to several requirements. SPP RE modified the proposed Standard in response to NERC's suggestions.

NERC posted the proposed regional Reliability Standard for a 45-day public comment period from August 15, 2012 through September 28, 2012. Stakeholders were asked to provide feedback on proposed PRC-006-SPP-01 and associated documents through a special electronic comment form. There were 10 sets of comments, including comments from more than 11 different individuals from approximately 10 companies representing 6 of the 10 industry segments.

VI. CONCLUSION

For the reasons stated above, NERC respectfully requests that the Commission approve the proposed PRC-006-SPP-01 regional Reliability Standard, the associated proposed VRFs and VSLs included in **Exhibits A and G** to this filing, and the implementation plan for proposed PRC-006-SPP-01 included in **Exhibit C** of this filing.

Respectfully submitted,

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April 26, 2013

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 26th day of April, 2013.

/s/ William H. Edwards
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Counsel for North American Electric Reliability Corporation

Exhibit A

Proposed Regional Reliability Standard PRC-006-SPP-01

A. Introduction

1. **Title:** Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding

2. **Number:** PRC-006-SPP-01

3. **Purpose:** To develop, coordinate and document 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 Coordinator

   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. Generator Owners

5. **Effective Date:** Requirements R4, R5, and R6 shall become effective the first day of the first calendar quarter one year after regulatory approval.

   The remaining requirements shall become effective the first day of the first calendar quarter three years after regulatory approval.

6. **Basis for Standard Development:** UFLS entity's planning data for the upcoming calendar year.

B. Requirements and Measures

R1. Each UFLS entity that has a total forecasted peak Load greater than or equal to 100 MW shall develop and implement an automatic UFLS program that meets the following requirements: [VRF: High][Time Horizon: Long-term Planning]

   1.1. A minimum of 10% shall be shed at each UFLS step in accordance with the table below.

(1) UFLS Step	(2) Frequency (hertz)	(3) Minimum accumulated load relief as percentage of forecasted peak Load (%)	(4) Maximum accumulated load relief as percentage of forecasted peak Load (%)
1	59.3	10	25
2	59.0	20	35
3	58.7	30	45

1.2. The intentional relay time delay for UFLS shall be less than or equal to 30 cycles.

1.3. Undervoltage inhibit setting shall be less than or equal to 85 percent of nominal voltage.

M1. Each UFLS entity shall have evidence such as reports, program plans, or other documentation of its UFLS program that demonstrates it meets requirement R1 Parts 1.1 through 1.3.

R2. Each UFLS entity that has a total forecasted peak Load less than 100 MW shall develop and implement an automatic UFLS program that meets the following requirements: [VRF: Medium][Time Horizon: Long-term Planning]

2.1. A minimum of one UFLS step with the frequency set point as assigned by the Planning Coordinator.

2.2. The minimum accumulated Load relief shall be at least 30% of the forecasted peak Load.

2.3. The intentional relay time delay for UFLS shall be less than or equal to 30 cycles.

2.4. Undervoltage inhibit setting shall be less than or equal to 85 percent of nominal voltage.

M2. Each UFLS entity shall have evidence such as reports, program plans, or other documentation of its UFLS program that demonstrates it meets requirement R2 Parts 2.1 through 2.4.

R3. Each UFLS entity electing to use underfrequency islanding schemes shall design those islanding schemes to operate after all 3 steps of UFLS have been exhausted and the frequency continues to fall to 58.5 Hz or below. For islanding schemes designed to operate at or between 58.5 Hz and 58.0 Hz, the minimum time delay shall be 2 seconds. For islanding schemes designed to operate below 58.0 Hz, no time delay is required. [VRF: Lower][Time Horizon: Long-term Planning]

M3. Each UFLS entity electing to use islanding schemes shall have evidence such as reports, program plans, or other documentation of its UFLS program that demonstrates it meets requirement R3.

R4. The Planning Coordinator shall perform and document a UFLS technical assessment within one year after the occurrence of any of the following situations: [VRF: Medium][Time Horizon: Long-term Planning]

- Performance characteristic changes to PRC-006 or the SPP UFLS standard.
- Changes to the boundaries of a specified island are identified.

M4. The Planning Coordinator shall have evidence that it performed a technical assessment per requirement R4.

R5. Each UFLS entity shall maintain and submit the following UFLS data based on the forecasted peak Load to the Planning Coordinator within (30) calendar days upon request from the Planning Coordinator: [VRF: Lower][Time Horizon: Long-term Planning]

5.1. Location of installed UFLS equipment

5.2. Trip frequency(s) for each location

5.3. Total relay operating time of each location (time required for the relay to reliably sense the frequency + intentional delay time (if any))

5.4. Breaker operating time (nameplate) of each location

5.5. Percentage and/or MW of bus load to be shed at the location

5.6. Total amount of load shed by each trip frequency and the total forecasted peak Load

5.7. Tie tripping schemes and the frequency and time delay at which they operate

5.8. Islanding schemes and the frequency and time delay at which they operate

M5. Each UFLS entity shall have evidence that the information was supplied to the Planning Coordinator per requirement R5.

R6. Each Generator Owner shall maintain and submit the following data to the Planning Coordinator within (30) calendar days upon request from the Planning Coordinator: [VRF: Lower][Time Horizon: Long-term Planning]

6.1. Location of underfrequency and overfrequency equipment

6.2. Trip frequency(s) for each location

6.3. Total relay operating time of each location (time required for the relay to reliably sense the frequency + intentional delay time (if any))

6.4. Breaker operating time (nameplate) of each location

6.5. MW of generation shed at each location

M6. Each Generator Owner shall have evidence that the information was supplied to the Planning Coordinator per requirement R6.

R7. Each Generator Owner shall verify that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2 as a result of the unit(s) frequency protective relay settings. [VRF: Medium][Time Horizon: Long-term Planning]

7.1. For generating units with operating characteristics that limit the unit's ability to perform in accordance with R7, the Generator Owner shall provide to the Planning Coordinator technical evidence demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings.

M7. Each Generator Owner shall have evidence that it complies with R7 or that the information was supplied to the Planning Coordinator, if appropriate, as required in R7.1.

R8. The Planning Coordinator shall determine if the Generator Owner has provided technical evidence demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings. [VRF: Medium][Time Horizon: Long-term Planning]

8.1. The Planning Coordinator shall determine if the UFLS program performance is degraded due to the removal of any generation identified in accordance with R7.1 and verified in accordance with R8.

8.1.1. If the Planning Coordinator determines the UFLS program is degraded in accordance with R8.1 and that supplementary load shedding is, therefore, required, the Planning Coordinator shall notify the Generator Owner or UFLS entity(s) in accordance with the following:

- Where the Generator Owner is a UFLS Entity and has the required amount of supplementary Load available, the Planning Coordinator shall notify the Generator Owner of Load the entity is required to shed (in addition to that required in accordance with R1 and R2)

- Where the Generator Owner is not a UFLS Entity, or does not have the required supplementary Load available for shedding, the Planning Coordinator shall notify any other UFLS Entity(s) within the Planning Coordinator Area of Load the entity(s) is required to shed (in addition to that required in accordance with R1 and R2)

M8. The Planning Coordinator shall have evidence that it complies with the requirements in R8.

R9. The Generator Owner or other UFLS entity(s) shall implement supplementary shedding of Load required by the Planning Coordinator in accordance with R8.1.1. [VRF: Medium][Time Horizon: Long-term Planning]

M9. The Generator Owner or other UFLS entity shall have evidence that it complies with the requirements in R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

SPP Regional Entity
SERC (for Planning Coordinator only)

1.2. Data Retention

The Planning Coordinator and each UFLS entity and Generator Owner shall keep data or dated evidence to show compliance as identified below unless directed by SPP Regional Entity to retain specific evidence for a longer period of time as part of an investigation:

- Each UFLS entity shall retain the current evidence of Requirements R1 or R2, and R3, Measures M1 or M2, and M3, as well as any evidence necessary to show compliance since the last compliance audit.

- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator since the last compliance audit in accordance with Requirement R5, Measure M5.

- The Planning Coordinator shall retain the current evidence of Requirement R4, Measure M4 as well as any evidence necessary to show compliance since the last compliance audit.

- Each Generator Owner shall retain evidence of UFLS data transmittal to the Planning Coordinator since the last compliance audit in accordance with Requirement R6, Measure M6.

- Each Generator Owner shall retain evidence of Requirements R7, Measures M7 as well as any evidence necessary to show compliance since the last compliance audit.

If the Planning Coordinator, UFLS entity or Generator Owner 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.

1.3. Compliance Monitoring and Assessment Process

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

1.4. Additional Compliance Information

UFLS entities may implement an aggregated UFLS program with other UFLS entities. In R1 and R2, the 100 MW limit refers to the aggregated UFLS program, if one exists.

2. Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Long-Term Planning	High	N/A	UFLS entity developed a program, but failed to meet any one (1) of the following 5 requirements: Part 1.1 (Step1-3) Part 1.2 Part 1.3	UFLS entity developed a program, but failed to meet any two (2) of the following 5 requirements: Part 1.1 (Step1-3) Part 1.2 Part 1.3	UFLS entity developed a program, but failed to meet three (3) or more of the following 5 requirements: Part 1.1 (Step1-3) Part 1.2 Part 1.3 OR Failed to develop a UFLS program
R2	Long-Term Planning	Medium	UFLS entity developed a program, but failed to meet one (1) of the requirements in Parts 2.1 through 2.4	UFLS entity developed a program, but failed to meet two (2) of the requirements in Parts 2.1 through 2.4	UFLS entity developed a program, but failed to meet three (3) of the requirements in parts 2.1 through 2.4	UFLS entity developed a program, but failed to meet all four (4) of the requirements in Parts 2.1 through 2.4 OR Failed to develop a UFLS program
R3	Long-	Lower	N/A	N/A	N/A	UFLS entity, electing to

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
	Term Planning					use underfrequency islanding schemes, failed to develop an islanding scheme per the requirement
R4	Long-Term Planning	Medium	The Planning Coordinator performed a technical assessment within five years and three months or within one year and three months after one of the situations listed in R4	The Planning Coordinator performed a technical assessment within five years and six months or within one year and six months after one of the situations listed in R4	The Planning Coordinator performed a technical assessment within five years and nine months or within one year and nine months after one of the situations listed in R4	The Planning Coordinator performed a technical assessment within six years or within two years after one of the situations listed in R4 OR The Planning Coordinator failed to perform a technical assessment
R5	Long-Term Planning	Lower	UFLS entity provided required data more than 30 calendar days and up to and including 45 calendar days following the request	UFLS entity provided required data more than 45 calendar days and up to and including 60 calendar days following the request OR UFLS entity did not provide one piece of information listed in R5	UFLS entity provided required data more than 60 calendar days and up to and including 75 calendar days following the request OR UFLS entity did not provide two pieces of information listed in R5	UFLS entity provided required data more than 75 calendar days following the request OR UFLS entity did not provide required data after the request was made

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
				(e.g., 5.1.)	(e.g., 5.1. and 5.2.)	OR UFLS entity did not provide three or more pieces of information listed in R5 (e.g., 5.1. and 5.2. and 5.3.)
R6	Long-Term Planning	Lower	Generator Owner provided required data more than 30 calendar days and up to and including 45 calendar days following the request	Generator Owner provided required data more than 45 calendar days and up to and including 60 calendar days following the request OR Generator Owner did not provide one piece of information listed in R6 (e.g., 6.1.)	Generator Owner provided required data more than 60 calendar days and up to and including 75 calendar days following the request OR Generator Owner did not provide two pieces of information listed in R6 (e.g., 6.1. and 6.2.)	Generator Owner provided required data more than 75 calendar days following the request OR Generator Owner did not provide required data after the request was made OR Generator Owner did not provide three or more pieces of information listed in R6 (e.g., 6.1. and 6.2. and 6.3.)

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R7	Long-Term Planning	Medium	N/A	N/A	The Generator Owner did not provide technical evidence to the Planning Coordinator demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings for their generating units with operating characteristics that limit the unit's ability to perform in accordance with R7.	The Generator Owner did not verify that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2 due to the generator unit frequency protective relay settings.
R8	Long-Term Planning	Medium	N/A	N/A	The Planning Coordinator determined that the UFLS program was degraded in accordance with R8.1, but did not notify the Generator Owner or the UFLS entity of the Load that they were required to shed.	The Planning Coordinator did not determine if the UFLS program performance was degraded due to the removal of any generation identified in accordance with R7.1 and verified in accordance

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
						with R8.
R9	Long-Term Planning	Medium	N/A	N/A	N/A	The Generator Owner or other UFLS entity did not implement supplementary shedding of Load required by the Planning Coordinator in accordance with R8.1.1.

D. Associated Documents

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Note:
UFLS program performance will be measured based on the entity's planning values and not the one-minute average of the entity's load prior to the first underfrequency relay action. This has changed from the current SPP Criteria.

Rationale for R1:
The current SPP UFLS program includes three separate UFLS steps with a minimum load shedding percentage of 10%, 20%, and 30%, cumulatively, for each of the three steps. These have remained unchanged from the SPP Criteria. The SDT believed that it was reasonable to increase the maximum load shedding percentages in steps 1 and 2. The maximum load shedding percentages in steps 1 and 2 were increased from 15% and 30%, respectively, to 25% and 35%, allowing more flexibility for those steps.

Total forecasted peak Load is the projected planning value of an entity's end-use customers' coincident system peak load for the upcoming calendar year.

Rationale for R2:

The SDT realized that some small UFLS entities may experience difficulty in achieving more than one UFLS step due to a smaller arrangement of loads and meeting the tolerances set forth in the load shedding table of R1.1. The basis for selecting 100 MW as the threshold comes from the use of this same value in other regional UFLS standards and a reasonable judgment that the total forecasted load served by most smaller electric utilities is less than 100 MW. R2 was structured to accommodate these small entities and its inclusion within this standard indicates the importance of having all entities participate in the UFLS program.

Rationale for R3:

UFLS entities may elect to implement schemes following operation of all three underfrequency steps should the frequency continue to decay. The SDT believes that a time delay on initiation of islanding for frequencies slightly below the third step of load shedding is necessary to allow time for system recovery and to accommodate some frequency overshoot. The SPP UFLS study, conducted by Powertech, showed that frequency excursions between 58.5 and 58.0 Hz would recover in less than 2 seconds. Therefore, having a 2 second time delay may avoid islanding.

This Requirement does not include Out-of-Step trip relaying designed to isolate portions of the power grid for unstable power swings.

Rationale for R4:

Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS is required by NERC PRC-006-0 R1.3 to be conducted periodically (at least every five years or required by changes in system conditions). The purpose of the SPP UFLS requirement R4 is to expand upon NERC PRC-006-0 R1.3. "Changes in system conditions" includes performance characteristic changes in PRC-006 or this SPP UFLS document. This also includes changes to the boundaries of a specified island, for example when Nebraska was brought into the SPP specified island. The SDT believes after such changes it is imperative to perform a new assessment to ensure UFLS program effectiveness.

Rationale for R5:

The NERC standard requires that; "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." The information requested in R5 is the data required by the Planning Coordinator to model the UFLS program and maintain compliance to the NERC standard.

Rationale for R6:

The SDT believes this generator data is needed by the Planning Coordinator for the following reasons:
1.) better modeling for UFLS technical assessments,
2.) performing routine UFLS studies, and
3.) post-event analysis.

This data will enable the Planning Coordinator to evaluate whether the generator can meet the R7 requirement and determine if additional load shedding is required on the part of the UFLS entities.

Rationale for R7:

In order to effectively study and evaluate the performance of the UFLS system the generator relay protection trip values must be known. The ultimate goal is to balance the generation and load so that a total collapse does not occur. Therefore, the generator trip values are critical to evaluating the performance of the UFLS system. With this information the system can then be studied.

Rationale for R8:

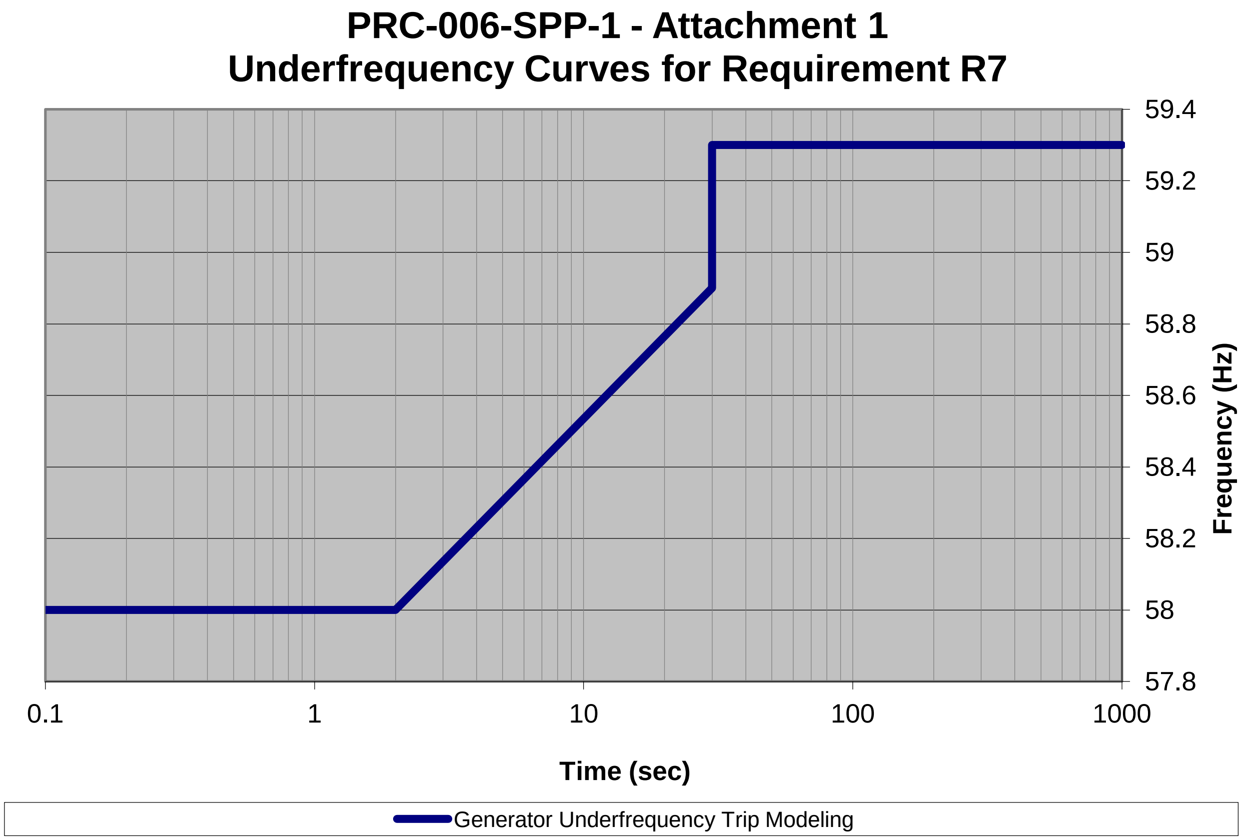
The Planning Coordinator is required to verify the Generator Owner's technical justification for not being able to operate throughout the Attachment 1 and 2 curves and to review the consequences to the UFLS program performance for the loss of that additional generation after the initiation of an under frequency event. It also provides a mechanism for the Planning Coordinator to resolve the detrimental effects of the loss of this additional generation if it determines that the performance of the UFLS program is degraded.

Rationale for R9:

The SDT's decision to include R9 is to prevent blackouts caused by early removal of generating units from the system. In a real time load shedding event, if the UFLS is degraded in accordance with R8.1.1, removal of units will make the system condition worse. This is the main reason for the supplementary shedding of loads to compromise the loss of generation. This action is critical to bring back the unstable system to stable.

Version History

Version	Date	Action	Change Tracking
1	July 30, 2012	SPP Board of Directors approved	
1	November 7, 2012	Adopted by NERC Board of Trustees	


PRC-006-SPP-1 - Attachment 1
Underfrequency Curves for Requirement R7
59.4
59.2
59
58.8
58.6
58.4
58.2
58
57.8
Frequency (Hz)
0.1
1
10
100
1000
Time (sec)
Generator Underfrequency Trip Modeling

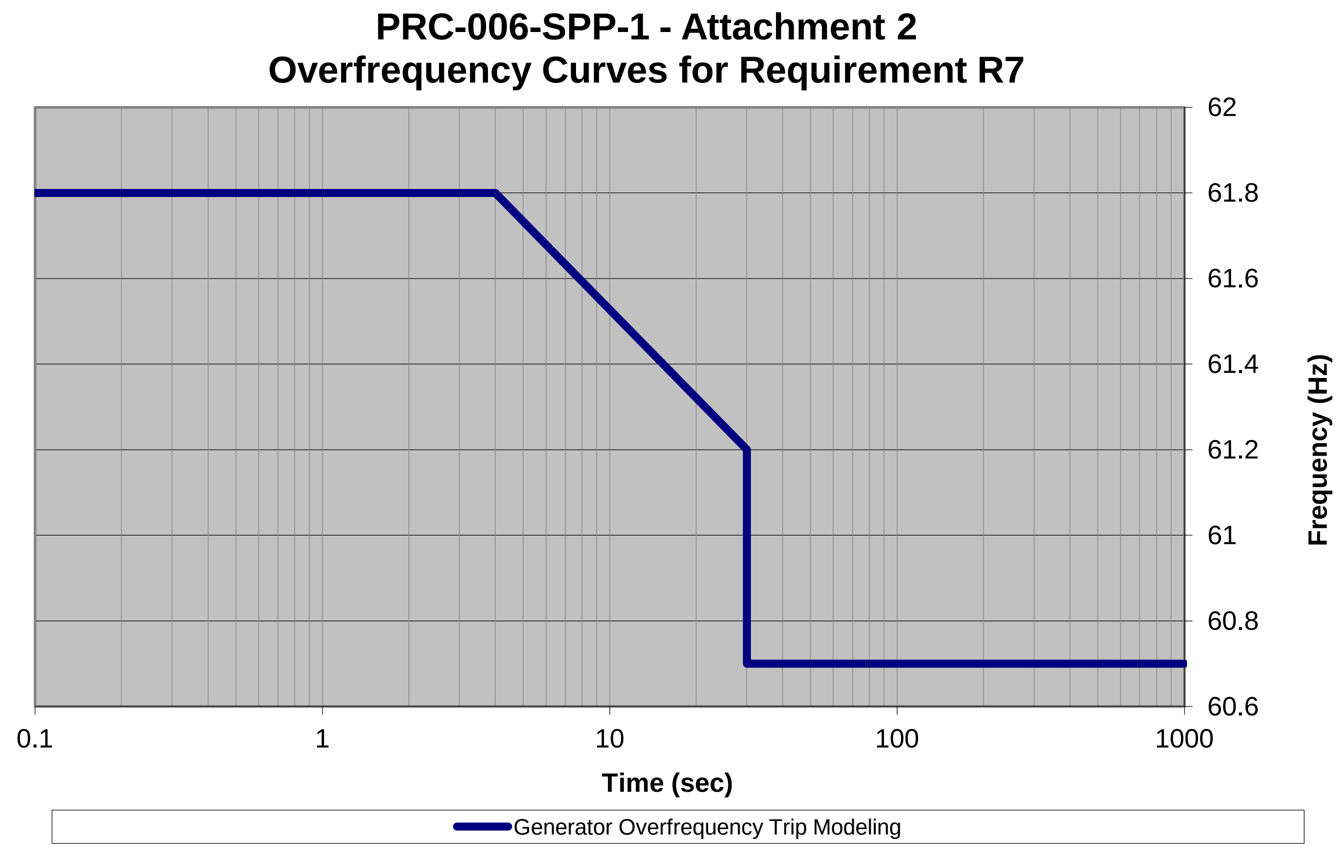

PRC-006-SPP-1 - Attachment 2
Overfrequency Curves for Requirement R7
62
61.8
61.6
61.4
61.2
61
60.8
60.6
Frequency (Hz)
0.1
1
10
100
1000
Time (sec)
Generator Overfrequency Trip Modeling

Exhibit B

Order No. 672 Criteria

EXHIBIT B

Order No. 672 Criteria for Proposed PRC-006-SPP-01

In Order No. 672,[1] the Commission identified a 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 discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

SPP RE and its members believe that a region-wide, fully coordinated single set of UFLS requirements is necessary to create an effective and efficient UFLS program, and their industry experience has supported that belief. The goal of PRC-006-SPP-01 is to further protect the reliability of the Bulk Power System and to provide system stability in the case of an UFLS situation by requiring Generator Owners to be involved in the UFLS process. The proposed PRC-006-SPP-01regional Reliability Standard is

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

[2] 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 Cybersecurity protection.

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.

technically sound because it utilizes existing practices that have been in place for SPP RE members per the SPP Criteria and has been proven successful. The proposed regional Standard will include all registered entities responsible for UFLS locations, including non-members of SPP located within the SPP RE footprint, expanding the coverage area that the SPP Criteria covers and providing additional protections to the reliability of the Bulk Power System.

Proposed PRC-006-SPP-01 is more stringent than the continent-wide Reliability Standard PRC-006 because it includes Generator Owners as applicable entities. By requiring Generator Owners to report to the Planning Coordinator, there is a broader picture of what generation and load is needed to balance the system; ensuring reliable operations of the Bulk Power System. Proposed PRC-006-SPP-01 Requirement R6 requires Generator Owners to submit data to the Planning Coordinator within thirty (30) calendar days upon request from the Planning Coordinator. The data includes: location of underfrequency and overfrequency equipment, trip frequency(s) for each location, total relay operating time of each location, breaker operating time of each location, and MW of generation shed at each location. The generator data is needed by the Planning Coordinator to create better modeling for UFLS technical assessments; to perform routine UFLS studies; and to assist in better post-event analysis. The data provided by Generator Owners will enable the Planning Coordinator to evaluate whether the generator can meet the requirements of Requirement R7 and determine if additional load shedding is required. Improved technical assessments assists in protecting the reliability of the Bulk Power System because there is a more accurate picture of what is needed to prevent UFLS events.

Proposed PRC-006-SPP-01 Requirement R7 requires Generator Owners to verify that the Generator Owners' generating unit(s) will not trip above the generator underfrequency curve (see Attachment 1 of proposed PRC-006-SPP-01) and will not trip below the generator overfrequency curve (see Attachment 2 of proposed PRC-006-SPP-01) as a result of the unit(s) frequency protective relay settings. To effectively study and evaluate the performance of the UFLS system, the generator relay protection trip values must be known and are critical to evaluating the performance of the UFLS system. The goal is to balance the generation and load so a total collapse of the system does not occur, therefore, protecting the Bulk-Power System. For generating units with operating characteristics that limit the unit's ability to perform in accordance with R7, proposed PRC-006-SPP-01 Requirement R7.1, requires Generator Owners to provide the Planning Coordinator technical evidence demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings.

Proposed PRC-006-SPP-01 Requirement R8 requires the Planning Coordinator to verify the Generator Owner's technical justification for not being able to operate based upon Attachment 1 "Underfrequency Curves" and Attachment 2 "Overfrequency Curves" and to review the potential consequences to the UFLS program performance for additional generation loss after the initiation of an underfrequency event. The Requirement also provides a mechanism for the Planning Coordinator to resolve the detrimental effects of the loss of this additional generation if the Planning Coordinator determines that the performance of the UFLS program is degraded. Proposed PRC-006-SPP-01 Sub-Requirement R8.1.1 requires the Planning Coordinator to inform the

Generator Owners either; 1) the Load the entity is required to shed (in addition to that required in accordance with Requirement R1 and Requirement R2); or 2) if the supplementary Load is not available for shedding by the Generator Owners, the Planning Coordinator shall notify any other UFLS Entity(s) within the Planning Coordinator Area of Load the entity(s) is required to shed (in addition to that required in accordance with Requirement R1 and Requirement R2).

Proposed PRC-006-SPP-01 Requirement R9 requires the Generator Owners or other UFLS entities to implement supplementary shedding of Load required by the Planning Coordinator as defined in proposed PRC-006-SPP-01 Requirement R8.1.1. The intent of this Requirement is to prevent blackouts caused by early removal of generating units from the system. In a real time load shedding event, if the UFLS program is degraded in accordance with Requirement R8.1.1, removal of the unit would make the system worse. The supplementary shedding of Load is critical to bring stability to the system and to protect the reliability of the Bulk-Power System.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

Proposed PRC-006-SPP-01 is only applicable to Generator Owners, Planning Coordinators, and UFLS entities within the SPP RE region. UFLS entities are defined in the applicability section of the proposed regional Reliability Standard to include "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." The entities may include

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[3] 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.

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.

Transmission Owners and Distribution Providers. As explained in greater detail in the petition, the proposed regional Reliability Standard contains nine Requirements, which clearly state the entity that is expected to comply and identify what is required.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The VRFs and VSLs for the proposed regional Reliability Standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding Requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed regional Reliability Standard includes clear and understandable consequences in accordance with Order No. 672. Proposed PRC-006-SPP-01 also includes clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation. Upon approval by the Commission, the ranges of penalties for violations will be based on the applicable VRF and VSL in accordance with the sanctions table and the supporting penalty determination process described in the Commission-approved NERC Sanction Guidelines, Appendix 4B to the NERC Rules of Procedure. (*See* **Exhibit F** for additional discussion regarding the assigned VRFs and VSLs.)

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a

[4] 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.

consistent and non-preferential manner. [5]

Proposed PRC-006-SPP-01 identifies clear and objective criterion or measures for compliance so that it can be enforced in a consistent and non-preferential manner. The regional Reliability Standard contains individual measures that support the regional difference's Requirements by plainly identifying how the Requirements will be assessed and enforced. These six measures ensure that the Requirements will be assessed and enforced in a clear, consistent, and non-preferential manner, without prejudice to any party.

5. **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 or historical regional infrastructure design.**[6]

Proposed PRC-006-SPP-01 achieves its reliability goal effectively and efficiently. The proposed Standard sets minimum automatic UFLS design requirements which are similar to the design requirements in the current SPP UFLS Criteria . By utilizing and building on the existing SPP UFLS Criteria, the proposed regional Reliability Standard uses the most efficient method available to achieve the reliability goal and reduce the time and cost for implementation of the proposed regional Reliability Standard. UFLS program performance under the proposed PRC-006-SPP-01 will be measured based on the entity's planning values rather than the one-minute average of the entity's load prior to the first underfrequency relay action, which is used in the SPP UFLS Criteria. The

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5 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.

6 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.

SPP UFLS Criteria is based on an operations viewpoint that the three steps of the UFLS program had to be met "at any given time."

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

Proposed PRC-006-SPP-01 does not reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed PRC-006-SPP-01 was designed to be consistent with the continent-wide Reliability Standard, PRC-006, while adding specificity not contained in PRC-006-1 for the development, coordination, implementation, and analysis of UFLS schemes in the SPP region.

The implementation cost for smaller entities was considered during the development of proposed PRC-006-SPP-01. Reliability Standard PRC-006-1 requires the Planning Coordinator to identify which entities will participate in its UFLS scheme, including the number of steps and percent load an entity will shed. The standard drafting team recognized that some small UFLS entities may experience difficulty in achieving more than one UFLS step due to a smaller arrangement of loads and meeting the tolerances set forth in the load shedding table of Requirement R1.1. The standard drafting team made efforts to consider costs to implement for these smaller entities while

[7] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect 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.

protecting the reliability of the Bulk-Power System. The 100 MW threshold was selected to conform to other regional UFLS regional Reliability Standards, but primarily because the total forecasted load served by smaller electric utilities is less than 100 MW.

To address this issue, the standard drafting team included Requirement R2, which states that smaller entities with a total forecasted peak Load less than 100 MW shall not be required to have more than one UFLS step. This limits additional cost for these smaller entities to comply with the Standard, but with minimal consequence to the reliability of the Bulk-Power System.

7. **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 geographic area or regional model. It should take into account regional variations in the organization 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.[8]**

As a regional Reliability Standard, proposed PRC-006-SPP-01 will be enforceable for registered entities within the SPP RE footprint.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]**

[8] 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.

[9] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC 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.

Design and implementation of UFLS protection schemes in the SPP RE footprint, as required by proposed PRC-006-SPP-01 does not cause undue negative effect on competition or restriction of the grid. Specifically, the proposed regional Reliability Standard does not restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The implementation time for the proposed regional Reliability Standard is reasonable. Requirements R4, R5, and R6 will become effective the first day of the first calendar quarter one year after regulatory approval. The one year phase-in for implementation is needed for the Planning Coordinator to perform the studies necessary to assess the effectiveness of the UFLS program.

The remaining six requirements shall become effective the first day of the first calendar quarter three years after regulatory approval. The use of forecasted peak load will require changes to a registered entities system. The additional two year phase in for compliance is needed for any necessary changes to be made to the existing UFLS schemes.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

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[10] Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC 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.

[11] 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

The proposed Reliability Standard was developed in accordance with NERC's and SPP RE's Commission-approved processes for developing and approving Reliability Standards. SPP RE develops regional Reliability Standards in accordance with the SPP RE Standards Development Process Manual, which is included as Exhibit C of SPP RE's Regional Delegation Agreement with NERC. The development process is open to any person or entity with a direct and material interest in the bulk power system. Section V of this petition, *Summary of the Reliability Standard Development Proceedings,* details the processes followed to develop the Standard (for a more thorough review, please see the complete development history included as **Exhibits E and F**).

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all drafting team meetings had properly posted notices and were open to the public. The initial and recirculation ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC and SPP RE have not identified competing vital public interests with respect to the request for approval of the regional Reliability Standard, and no comments were received during the development of the regional Reliability Standard indicating conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate

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 FERC.

[12] 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.

factors.[13]

No other factors relevant to whether the proposed regional Reliability Standard is just and reasonable were identified.

[13] 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.

Exhibit C

Implementation Plan

Implementation Plan for SPP Underfrequency Load Shedding, PRC-006-SPP-01

Prerequisite Approvals

SPP Regional Entity Trustees

Proposed Effective Date

Requirements R4, R5, and R6 shall become effective the first day of the first calendar quarter one year after regulatory approval. The one year phase in for compliance is needed for the Planning Coordinator to perform the studies necessary to assess the effectiveness of the UFLS program.

The remaining requirements shall become effective the first day of the first calendar quarter three years after regulatory approval. The additional two year phase in for compliance is needed for any necessary changes to be made to the existing UFLS schemes.

Applicability

The entities listed in the Applicability section will be held responsible for their requirements according to the effective dates listed above.

Field Testing

None

Other Considerations

UFLS entities may implement an aggregated UFLS program with other UFLS entities. In R1 and R2, the 100 MW limit refers to the aggregated UFLS program, if one exists.

Exhibit D

NERC Consideration of Comments

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Regional Reliability Standard PRC-006-SPP-01

The Regional Reliability Standard PRC-006-SPP-01 Drafting Team thank all commenters who submitted comments on the Regional Reliability Standard **PRC-006-SPP-01**. This standard was posted for a 45-day public comment period from August 15, 2012 through September 28, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 10 sets of comments, including comments from more than 11 different people from approximately 10 companies representing 6 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

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 of Standards, Mark Lauby , at 404-446-2560 or via e-mail at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

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

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Vassallo	BPA, Transmission	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Individual	Jake Rice	City Water & Light			X							
3.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
4.	Individual	Tiffany Lake	Westar Energy	X		X		X	X				
5.	Individual	Gary Cox	Southwestern Power Administration	X								X	
6.	Individual	Doug Peterchuck	Omaha Public Power District	X		X		X	X				
7.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
8.	Individual	Alice Ireland	Southwestern Public Service Company, an Xcel Energy company	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Individual	Thad Ness	American Electric Power	X		X		X	X				
10.	Individual	Mayor Mark Piazza	City of Abbeville	X					X		X		

1. **Do you agree the proposed standard is being developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	Yes	
City Water & Light	Yes	
Salt River Project	Yes	
Westar Energy	Yes	
Southwestern Power Administration	Yes	
Southwestern Public Service Company, an Xcel Energy company	Yes	
American Electric Power	Yes	
City of Abbeville	Yes	
Omaha Public Power District	No	SPP's weighting structure allowed for a single vote to carry the complete weight of one of their five segments, (20%). Additionally, companies that qualify for more than one segment were only permitted to vote in one of the segments, rather than all that they were qualified to vote in. As chance would have it, only one of the SPP BA/TOP members cast their vote as a "Marketer/Broker" (of which many SPP members qualify for) and thus was

Organization	Yes or No	Question 1 Comment
		able to control the entire segment, i.e. 20% of the overall vote. If that vote were cast as negative or not cast at all, the regional standard would not have passed with the SPP membership. SPP membership companies' associates were also permitted to vote in the "End User and Public Interest" segment and thus able to control that segment as well (20%). It was explained that any individual, even those that work for a SPP membership company and/or those individuals participating on the Standard Drafting Team, are permitted to vote in the End User segment in addition to their company's vote. This "loophole" permits a company to vote 2, 3 or even 200+ times. The previously described 2 segments included only 5 total votes. These 2 segments unanimously approved the Regional Standard. However the 3 segments that will be directly affected by the approval of this Regional Standard were adamantly opposed to its approval having voted as follows: Transmission (53%), Generation (71%), Distribution/LSE (53%). These 3 segments cast 36 votes, or 88% of the total votes cast on this Regional Standard.

Response: The proposed PRC-006-SPP-01 Under Frequency Load Shedding Standard (PRC-006-SPP-01) was developed in a fair and open process, using the NERC and FERC-approved Southwest Power Pool Regional Entity Standards Development Process Manual (SPP RE Manual). Contrary to OPPD's assertion, "the 3 segments that will be directly affected by the approval of this Regional Standard" were not adamantly opposed to PRC-006-SPP-01; all five voting segments, not just the End User and Marketer/Broker segments, voted in the majority for approval of PRC-006-SPP-01. A Standards Process Manual Task Force (SPMTF) has been established to identify and propose revisions (RSR-002: Proposed Revision 1 – SPP Regional Entity Standard Development Process Manual) to appropriately address questions and concerns raised during the initial implementation of the SPP RE Manual.

The SPP RE Manual provides:

1. "An interested party may only register in one segment." (Section V, Step 5, SPP Segment Weighted Voting, pg 15. Also see 119 FERC 61,060, Paragraph 418, pg. 134 in which FERC stated "We clarify that we expect SPP to follow a one-entity/one-vote policy.")

Organization	Yes or No	Question 1 Comment

2. "Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the Bulk Power System has a right to participate by: a) expressing a position and its basis, b) having that position considered, c) voting on a proposed regional reliability standard through a segment weighted balanced process, and d) having the right to appeal." (Introduction, pg 3).

3. "Votes will be counted by voting segment. Each voting segment will receive 20% of the vote." (Section V, Step 5, SPP Segment Weighted Voting, pg 15)

4. "The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. In all cases, the request for appeal must be made prior to the next step in the process." (Appendix A, II. Appeals, pg. 19)[2]

Persons, organizations, companies, government agencies, and individuals were allowed to participate in development of PRC-006-SPP-01, including voting on the proposed standard. All UFLS Standard Drafting Team (SDT) meetings were open and posted on SPP's public website, and the SDT provided reports to numerous Market and Operations Policy Committee and Regional Entity Trustee meetings. As required by the SPP RE Manual and the FERC order, entities were allowed to register and vote in only one segment. In determining the voting results, each of the voting segments received equal (20%) weighting. (Unlike the NERC Registered Ballot Body Criteria, the SPP RE Manual does not include any provisions that prohibit employees of organizations or companies from also registering and voting on proposed standards; nor does the SPP RE Manual include any provisions that allow for a proportional reduction in the weight given to segments that have a limited number votes.)

Regarding the registered ballot body voting results, all five of the segments had a majority affirmative vote: 53% voted yes in Transmission, 71% voted yes in Generation, 100% voted yes in Marketer/Broker, 53% voted yes in Distribution/LSE, and 100% voted yes in End User/Public Interest. These affirmative majorities do not indicate that any segments "were adamantly opposed."

Consistent with SPP's core value of continuous improvement, SPP RE is addressing stakeholder's concerns regarding segment weighting, segment qualifications, and "one entity one vote" through the Standards Process Manual Task Force (SPMTF). The SPMTF is

[2] Although OPPD requested clarification regarding SPP RE's determination of the voting results, it did not submit any appeals to any actions regarding PRC-006-SPP-01 development or balloting.

Organization	Yes or No	Question 1 Comment
serving as the Standard Drafting Team for revising the SPP RE Manual; all stakeholders who asked to serve on the SPMTF, including representatives from OPPD and LES, were appointed.		
Lincoln Electric System	No	SPP's weighting structure allowed for a single vote to carry the complete weight of one of their five segments, (20%). Additionally, companies that qualify for more than one segment were only permitted to vote in one of the segments, rather than all that they were qualified to vote in. As chance would have it, only one of the SPP BA/TOP members cast their vote as a "Marketer/Broker" (of which many SPP members qualify for) and thus was able to control the entire segment, i.e. 20% of the overall vote. If that vote were cast as negative or not cast at all, the regional standard would not have passed with the SPP membership. SPP membership companies' associates were also permitted to vote in the "End User and Public Interest" segment and thus able to control that segment as well (20%). It was explained that any individual, even those that work for a SPP membership company and/or those individuals participating on the Standard Drafting Team, are permitted to vote in the End User segment in addition to their company's vote. This "loophole" permits a company to vote 2, 3 or even 200+ times.The previously described 2 segments included only 5 total votes! These 2 segments unanimously approved the Regional Standard. However the 3 segments that will be directly affected by the approval of this Regional Standard were adamantly opposed to its approval having voted as follows: Transmission (53%), Generation (71%), Distribution/LSE (53%). These 3 segments cast 36 votes, or 88% of the total votes cast on this Regional Standard.
Response: The proposed PRC-006-SPP-01 Under Frequency Load Shedding Standard (PRC-006-SPP-01) was developed in a fair and open process, using the NERC and FERC-approved Southwest Power Pool Regional Entity Standards Development Process Manual (SPP RE Manual). Contrary to Lincoln Electric System's assertion, "the 3 segments that will be directly affected by the approval of this Regional Standard" were not adamantly opposed to PRC-006-SPP-01; all five voting segments, not just the End User and Marketer/Broker segments, voted in the majority for approval of PRC-006-SPP-01. A Standards Process Manual Task Force (SPMTF) has been established		

Organization	Yes or No	Question 1 Comment

to identify and propose revisions (RSR-002: Proposed Revision 1 – SPP Regional Entity Standard Development Process Manual) to appropriately address questions and concerns raised during the initial implementation of the SPP RE Manual.

The SPP RE Manual provides:

5. "An interested party may only register in one segment." (Section V, Step 5, SPP Segment Weighted Voting, pg 15. Also see 119 FERC 61,060, Paragraph 418, pg. 134 in which FERC stated "We clarify that we expect SPP to follow a one-entity/one-vote policy.")

6. "Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the Bulk Power System has a right to participate by: a) expressing a position and its basis, b) having that position considered, c) voting on a proposed regional reliability standard through a segment weighted balanced process, and d) having the right to appeal." (Introduction, pg 3).

7. "Votes will be counted by voting segment. Each voting segment will receive 20% of the vote." (Section V, Step 5, SPP Segment Weighted Voting, pg 15)

8. "The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. In all cases, the request for appeal must be made prior to the next step in the process." (Appendix A, II. Appeals, pg. 19)[3]

Persons, organizations, companies, government agencies, and individuals were allowed to participate in development of PRC-006-SPP-01, including voting on the proposed standard. All UFLS Standard Drafting Team (SDT) meetings were open and posted on SPP's public website, and the SDT provided reports to numerous Market and Operations Policy Committee and Regional Entity Trustee meetings. As required by the SPP RE Manual and the FERC order, entities were allowed to register and vote in only one segment. In determining the voting results, each of the voting segments received equal (20%) weighting. (Unlike the NERC Registered Ballot Body Criteria, the SPP RE

[3] Although Lincoln Electric System requested clarification regarding SPP RE's determination of the voting results, it did not submit any appeals to any actions regarding PRC-006-SPP-01 development or balloting.

Organization	Yes or No	Question 1 Comment
Manual does not include any provisions that prohibit employees of organizations or companies from also registering and voting on proposed standards; nor does the SPP RE Manual include any provisions that allow for a proportional reduction in the weight given to segments that have a limited number votes.) Regarding the registered ballot body voting results, all five of the segments had a majority affirmative vote: 53% voted yes in Transmission, 71% voted yes in Generation, 100% voted yes in Marketer/Broker, 53% voted yes in Distribution/LSE, and 100% voted yes in End User/Public Interest. These affirmative majorities do not indicate that any segments "were adamantly opposed." Consistent with SPP's core value of continuous improvement, SPP RE is addressing stakeholder's concerns regarding segment weighting, segment qualifications, and "one entity one vote" through the Standards Process Manual Task Force (SPMTF). The SPMTF is serving as the Standard Drafting Team for revising the SPP RE Manual; all stakeholders who asked to serve on the SPMTF, including representatives from OPPD and LES, were appointed.		

2. **Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

Summary Consideration:

Organization	Yes or No	Question 2 Comment
Omaha Public Power District	Yes	This SPP project was initiated on 10/29/07 with the completion of a SPP Regional Standard Request Form. As stated in that form, the objective of the project was to meet the requirements of the NERC PRC-006-0 "Fill in the Blank" UFLS standard. The goal of the project was to take the SPP RTO UFLS Criteria and transform it into a SPP RE Regional standard. Note, in 2007 the SPP RE and SPP RTO boundaries aligned. In 2009, the Nebraska entities joined the SPP RTO, however as NE's RTO membership changes have no bearing on our RE compliance associations the SPP RE and SPP RTO boundaries no longer align. In general, a UFLS program should cover the entire RTO, or more specifically, the Planning Coordinator footprint, however approving this SPP RE Regional Standard will prohibit this. In only 2 of the 8 NERC RE Regions do the RE boundaries align with the RTO boundaries, thus it makes little sense to develop a UFLS program on a RE footprint basis as was originally required in the PRC-006-0 (version zero) standard. NERC recognized this fact and has assigned the responsibility of developing a UFLS program to the Planning Coordinators, i.e. the SPP RTO, in the new continent-wide NERC standard PRC-006-1. FERC also agrees with this approach as is evident in their NOPR to approve PRC-006-1 which the Commission filed on October 20, 2011 (Docket No. RM11-20-000). Within Paragraph 46 of this Order FERC states:Requirement R2.3 allows Planning Coordinators to "adjust the island boundaries to differ from the Regional Entity area boundaries by mutual consent where necessary" to preserve contiguous island boundaries that better reflect simulations. The Commission agrees that identifying island boundaries based on where they are likely to occur due to system characteristics, as opposed to

Organization	Yes or No	Question 2 Comment
		maintaining rigid Regional Entity area boundaries, should result in more effective UFLS programs. Accordingly, the Commission encourages cooperation among entities to create UFLS programs that set island boundaries based on where separations are expected to occur during an under frequency event.The proposed SPP RE regional standard assigns the responsibility of creating a UFLS program to the “UFLS Entities” (Transmission Owners and Distribution Providers) which contradicts with NERC’s and FERC’s belief that a UFLS program should be developed by the Planning Coordinator. It should be noted that currently within the SPP RE footprint there are 53 registered Distribution Providers and 40 registered Transmission Owners. We do not believe many of these small TOs and DPs are in any position to develop a UFLS program as required by R1 and R2 of the proposed SPP RE standard, nor do they have the wide area view necessary to set up islanding schemes as required in R3 of the SPP RE standard.Additionally, the SPP RE regional standard is in direct conflict with NERC’s PRC-006-1 standard. The NERC approved standard requires the SPP Planning Coordinator to create a UFLS program, however the SPP RE standard requires all of the UFLS entities to create a program. As written, the SPP RE UFLS entities will have 2 programs to follow, the Planning Coordinator’s and their own. Also, some of the Requirements (R4 and R5) in the proposed SPP RE standard are duplicative of the NERC standard and therefore are not needed in the Regional Standard. As mentioned above, Nebraska entities will not fall under this regional requirement, as NPPD, OPPD, and LES are individually registered with the MRO. It is a concern of the Nebraska entities that if and when the SPP RTO (Planning Coordinator for the Nebraska Entitites) leans on the regional UFLS standard as the “PC UFLS Plan”, gaps in compliance and reliability will exist. Without a formal PC UFLS plan, Nebraska entities will not be able to meet compliance with the continent wide PRC-006-1 standard.
Response: NERC PRC-006 is not applicable to Generator Owners. The only way to enforce the Generator Owners’ participation in the UFLS program is to create a Regional Standard. The SPP UFLS SDT believes that the UFLS program needs to include Generator Owners since they have an essential part in balancing load and generation. PRC-024-1 is a NERC standard under development that will ensure that generating units remain connected during frequency excursions and ensure expected generating unit performance during		

Organization	Yes or No	Question 2 Comment
frequency excursions is communicated to the RC, PC, TOP, and TP for accurate system modeling. The Regional Standard approach would require all SPP RE registered entities in the SPP footprint to be held applicable to the SPP Regional Standard; this would include all NERC Registered Entities in the SPP Region. With only the NERC PRC-006 program approach, only those entities for which the SPP RTO is the Planning Coordinator would be held accountable to the UFLS program. Non-SPP members that are in the SPP RE footprint would not be held accountable to the UFLS program and thus would be required to develop their own or have another Planning Coordinator include them in their program. If SPP, as the Planning Coordinator, is responsible for the reliability of the SPP footprint, then SPP needs the authority of a Regional Standard to fulfill its responsibility. R3 does not require UFLS entities to utilize an islanding scheme. UFLS entities can elect to choose an islanding scheme. R4 and R5 are not duplicative of the NERC standard. The SPP Regional Standard contains requirements that are more stringent than the NERC standard.		
Lincoln Electric System	Yes	This SPP project was initiated on 10/29/2007 with the completion of a SPP Regional Standard Request Form. As stated in that form, the objective of the project was to meet the requirements of the NERC PRC-006-0 “Fill in the Blank” UFLS standard. The goal of the project was to take the SPP RTO UFLS Criteria and transform it into a SPP RE Regional standard. Note, in 2007 the SPP RE and SPP RTO boundaries aligned. In 2009, the Nebraska entities joined the SPP RTO, however as NE’s RTO membership changes have no bearing on our RE compliance associations the SPP RE and SPP RTO boundaries no longer align. In general, a UFLS program should cover the entire RTO, or more specifically, the Planning Coordinator footprint, however, approving this SPP RE Regional Standard will prohibit this. In only 2 of the 8 NERC RE Regions do the RE boundaries align with the RTO boundaries, thus it makes little sense to develop a UFLS program on a RE footprint basis as was originally required in the PRC-006-0 (version zero) standard. NERC recognized this fact and has assigned the responsibility of developing a UFLS program to the Planning Coordinators, i.e. the SPP RTO, in the new continent-wide NERC standard PRC-006-1. FERC also agrees with this approach as is evident in their NOPR to approve PRC-006-1 which the Commission filed on

Organization	Yes or No	Question 2 Comment
		October 20, 2011 (Docket No. RM11-20-000). Within Paragraph 46 of this Order FERC states:"Requirement R2.3 allows planning coordinators to “adjust the island boundaries to differ from the Regional Entity area boundaries by mutual consent where necessary” to preserve contiguous island boundaries that better reflect simulations. The Commission agrees that identifying island boundaries based on where they are likely to occur due to system characteristics, as opposed to maintaining rigid Regional Entity area boundaries, should result in more effective UFLS programs. Accordingly, the Commission encourages cooperation among entities to create UFLS programs that set island boundaries based on where separations are expected to occur during an under frequency event."The proposed SPP RE regional standard assigns the responsibility of creating a UFLS program to the “UFLS Entities” (Transmission Owners and Distribution Providers) which contradicts with NERC’s and FERC’s belief that a UFLS program should be developed by the Planning Coordinator. It should be noted that currently within the SPP RE footprint there are 53 registered Distribution Providers and 40 registered Transmission Owners. We do not believe many of these small TOs and DPs are in any position to develop a UFLS program as required by R1 and R2 of the proposed SPP RE standard, nor do they have the wide area view necessary to set up islanding schemes as required in R3 of the SPP RE standard.Additionally, the SPP RE regional standard is in direct conflict with NERC’s PRC-006-1 standard. The NERC approved standard requires the SPP Planning Coordinator to create a UFLS program, however the SPP RE standard requires all of the UFLS entities to create a program. As written, the SPP RE UFLS entities will have 2 programs to follow, the Planning Coordinator’s and their own. Also, some of the Requirements (R4 and R5) in the proposed SPP RE standard are duplicative of the NERC standard and therefore are not needed in the Regional Standard.
Response: NERC PRC-006 is not applicable to Generator Owners. The only way to enforce the Generator Owners’ participation in the UFLS program is to create a Regional Standard. The SPP UFLS SDT believes that the UFLS program needs to include Generator Owners since they have an essential part in balancing load and generation. PRC-024-1 is a NERC standard under development that will ensure that generating units remain connected during frequency excursions and ensure expected generating unit performance during frequency excursions is communicated to the RC, PC, TOP, and TP for accurate system modeling.		

Organization	Yes or No	Question 2 Comment
The Regional Standard approach would require all SPP RE registered entities in the SPP footprint to be held applicable to the SPP Regional Standard; this would include all NERC Registered Entities in the SPP Region. With only the NERC PRC-006 program approach, only those entities for which the SPP RTO is the Planning Coordinator would be held accountable to the UFLS program. Non-SPP members that are in the SPP RE footprint would not be held accountable to the UFLS program and thus would be required to develop their own or have another Planning Coordinator include them in their program. If SPP, as the Planning Coordinator, is responsible for the reliability of the SPP footprint, then SPP needs the authority of a Regional Standard to fulfill its responsibility. R3 does not require UFLS entities to utilize an islanding scheme. UFLS entities can elect to choose an islanding scheme. R4 and R5 are not duplicative of the NERC standard. The SPP Regional Standard contains requirements that are more stringent than the NERC standard.		
City Water & Light	No	Not to our knowledge.
Response: Thank you for your comment.		
Southwestern Public Service Company, an Xcel Energy company	No	Southwestern Public Service Company is in favor of this proposed regional standard. While the standard as proposed helps clarify many issues, there are two areas that may need additional clarification. In Requirement 8, it is unclear what would constitute a technical basis for operating outside the specified frequency range. One would assume this request for exception from the requirements of the standard would be reviewed by a technically oriented group, and that the basis would have to consider many factors.In addition, under Requirement 8.1.1, the method that the Planning Coordinator would use to allocate additional load shed to other UFLS entities in the event that a Generator Owner does not have supplementary load for shedding is unclear. This could place a disproportionate responsibility for shedding load on customers of other UFLS entities, without compensation or recourse.
Response: The SPP System Protection and Control Working Group will review all exceptions that are brought to the Planning Coordinator. The supplemental load shed approach was the position developed to represent the best balance between competing		

Organization	Yes or No	Question 2 Comment
entities while ensuring an adequate degree of reliability is achieved.		
American Electric Power	No	AEP is not aware of any potential adverse impacts to reliability or commerce in a neighboring region or interconnection that might occur as a result of the proposed standard.
Response: Thank you for your comment.		
Bonneville Power Administration	No	
Salt River Project	No	
Westar Energy	No	
Southwestern Power Administration	No	
City of Abbeville	No	

3. Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?

Summary Consideration:

Organization	Yes or No	Question 3 Comment
City of Abbeville	Yes	Yes, the financial impact of compliance on a small municipally owned system such as Abbeville,s could impact the welfare of our citizens.......
Response: The cost for smaller entities to implement was considered during PRC-006-SPP-01 development. NERC standard PRC-006-1 requires the Planning Coordinator to identify which entities will participate in its UFLS scheme, including the number of steps and percent load an entity will shed. The SPP UFLS SDT recognized that UFLS entities with a load of less than 100 MW may have difficulty in implementing more than one UFLS step and in meeting a tight tolerance. Accordingly, Requirement 2 states that such entities shall not be required to have more than one UFLS step. This should limit additional cost requirements for these smaller entities to comply with the standard, but with minimal consequence to operating system reliability.		
American Electric Power	No	AEP is not aware of any serious or substantial threats to public health, safety, welfare, or national security that might occur as a result of the proposed standard.
Response: Thank you for your comment.		
City Water & Light	No	Not to our knowledge.
Response: Thank you for your comment.		
Bonneville Power Administration	No	
Salt River Project	No	

Organization	Yes or No	Question 3 Comment
Westar Energy	No	
Southwestern Power Administration	No	
Omaha Public Power District	No	
Lincoln Electric System	No	
Southwestern Public Service Company, an Xcel Energy company	No	

4. **Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

Summary Consideration:

Organization	Yes or No	Question 4 Comment
City of Abbeville	Yes	Yes, there has is a serious burden financially the could prevent competitiveness...
Response: The cost for smaller entities to implement was considered during PRC-006-SPP-01 development. NERC standard PRC-006-1 requires the Planning Coordinator to identify which entities will participate in its UFLS scheme, including the number of steps and percent load an entity will shed. The SPP UFLS SDT recognized that UFLS entities with a load of less than 100 MW may have difficulty in implementing more than one UFLS step and in meeting a tight tolerance. Accordingly, Requirement 2 states that such entities shall not be required to have more than one UFLS step. This should limit additional cost requirements for these smaller entities to comply with the standard, but with minimal consequence to operating system reliability.		
City Water & Light	No	Not to our knowledge.
Response: Thank you for your comment.		
American Electric Power	No	AEP is not aware of any serious or substantial burden on competitive markets within the interconnection (that is not necessary for reliability) that might occur as a result of the proposed standard.
Response: Thank you for your comment.		
Bonneville Power Administration	No	
Salt River Project	No	

Organization	Yes or No	Question 4 Comment
Westar Energy	No	
Southwestern Power Administration	No	
Omaha Public Power District	No	
Lincoln Electric System	No	
Southwestern Public Service Company, an Xcel Energy company	No	

5. **Does the proposed regional reliability standard meet at least one of the following criteria?**

- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Summary Consideration:

Organization	Yes or No	Question 5 Comment
Southwestern Power Administration	Yes	I agree with all three statements
Response: Thank you for your comment.		
American Electric Power	Yes	While AEP would prefer to follow a single continent-wide approach in regard to this standard (and participated in the regional standard development process), we concur that the proposed standard meets at least one of the above criteria.
Response: Thank you for your comment.		
Bonneville Power Administration	Yes	
City Water & Light	Yes	
Westar Energy	Yes	
City of Abbeville	Yes	

Southwestern Public Service Company, an Xcel Energy company	Yes	
Omaha Public Power District	No	SPP's regional standard does not meet the criteria that FERC has indicated as being necessary in order to receive FERC's approval. FERC has indicated that they will consider approving regional differences (variances) and Regional Standards that meet the following criteria:Item 34: Â¶ 274 of the ERO Certification Order:"The Commission has stated that we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System. The FERC-approved definitions of Regional Standard (from the Rules of Procedure) are:"Regional reliability standard" means a type of reliability standards that is applicable only within a particular regional entity or group of regional entities. A regional reliability standard may augment, add detail to, or implement another reliability standard or cover matters not addressed by other reliability standards. Regional reliability standards, upon adoption by NERC and approval by the applicable ERO governmental authority(ies), shall be reliability standards and shall be enforced within the applicable regional entity or regional entities pursuant to delegated authorities.We do not believe that the SPP RE standard meets either of the FERC qualifications nor does it meet the FERC approved definition of a Regional reliability standard, which will likely have bearing on its approval at FERC. In addition to the SPP regional standard's failure to meet either the FERC qualifications or definition, there are also deficiencies within the proposed requirements. For Requirement R2, a UFLS entity with less than 100 MW of forecast peak load is expected to establish at least one UFLS step that sheds at least 30% of its load. However, R2 fails to state the frequency trip point for this step(s) and simply states it will be "assigned by the Planning Coordinator". Although SPP acknowledges within the standard that "some small

		UFLS entities may experience difficulty", the requirement fails to include a transparent decision-making process by which these small entities can express their concerns and understand SPP's process. Considering the NERC continent-wide standard, PRC-006-1 R14, allows for entities to submit comments with the understanding that their PC will respond, we believe such a process is important to include within a regional standard as well. Additionally, embedding the actual Frequency setpoints within the standard will only hinder the SPP RTO's ability to issue frequency setpoint changes as required by their own studies. Having a transparent decision-making process is a concept lacking within the proposed Requirement R8 as well. As written, R8 states that a Generator Owner must provide technical evidence demonstrating that a generating unit cannot be operated in the specified frequency range. If this is the case, the entity must shed supplementary load, if they have it. Despite the validity of the requirement, there is no indication of when such technical evidence must be provided or by what process or criteria the SPP Planning Coordinator will determine whether the entity's technical justification is acceptable and in compliance with R8.

Response: PRC-006-SPP-01 was created to be more stringent than the continent-wide Reliability Standard. Any duplicate requirements were removed from PRC-006-SPP-01.

The Planning Coordinator needs the flexibility to be able to assign small entities to different frequency trip points, depending on the location of the load, total number of small entities under 100 MW, and other factors.

Requirement 14 of the continent-wide standard requires PC's to respond to the comments from the UFLS entities. The SPP UFLS Standard does not include duplicate requirements from the continent-wide standard to remove any confusion over a possible double jeopardy situation.

The frequency setpoints for SPP's UFLS plan have not changed since the UFLS was originally created. None of the previous UFLS studies have indicated a need to alter from that approach. If the SPP system changes in the future and the UFLS study indicates a need to change the frequency setpoints, then SPP will change the Standard.

SPP, as the Planning Coordinator, will adopt the SPP Regional Standard as the SPP UFLS Plan.

The SPP System Protection and Control Working Group will review all exceptions that are brought to the Planning Coordinator.

Lincoln Electric System	No	SPP’s regional standard does not meet the criteria that FERC has indicated as being necessary in order to receive FERC’s approval. FERC has indicated that they will consider approving regional differences (variances) and Regional Standards that meet the following criteria:Item 34: Â¶ 274 of the ERO Certification Order:”The Commission has stated that we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System."The FERC-approved definitions of Regional Standard (from the Rules of Procedure) are:”Regional reliability standard” means a type of reliability standards that is applicable only within a particular regional entity or group of regional entities. A regional reliability standard may augment, add detail to, or implement another reliability standard or cover matters not addressed by other reliability standards. Regional reliability standards, upon adoption by NERC and approval by the applicable ERO governmental authority(ies), shall be reliability standards and shall be enforced within the applicable regional entity or regional entities pursuant to delegated authorities.We do not believe that the SPP RE standard meets either of the FERC qualifications nor does it meet the FERC approved definition of a Regional reliability standard, which will likely have bearing on its approval at FERC. In addition to the SPP regional standard’s failure to meet either the FERC qualifications or definition, there are also deficiencies within the proposed requirements. For Requirement R2, a UFLS entity with less than 100 MW of forecast peak load is expected to establish at least one UFLS step that sheds at least 30% of its load. However, R2 fails to state the frequency trip point for this step(s) and simply states it will be “assigned by the Planning Coordinator”. Although SPP acknowledges within the standard that “some small UFLS entities may experience difficulty”, the requirement fails to include a transparent decision-making process by which these small entities can express their concerns and understand SPP’s process. Considering the NERC continent-wide standard, PRC-006-1 R14, allows for entities to submit comments with the

		understanding that their PC will respond, we believe such a process is important to include within a regional standard as well.Having a transparent decision-making process is a concept lacking within the proposed Requirement R8 as well. As written, R8 states that a Generator Owner must provide technical evidence demonstrating that a generating unit cannot be operated in the specified frequency range. If this is the case, the entity must shed supplementary load, if they have it. Despite the validity of the requirement, there is no indication of when such technical evidence must be provided or by what process or criteria the SPP Planning Coordinator will determine whether the entity's technical justification is acceptable and in compliance with R8.
Response: PRC-006-SPP-01 was created to be more stringent than the continent-wide Reliability Standard. Any duplicate requirements were removed from PRC-006-SPP-01. The Planning Coordinator needs the flexibility to be able to assign small entities to different frequency trip points, depending on the location of the load, total number of small entities under 100 MW, and other factors. Requirement 14 of the continent-wide standard requires PC's to respond to the comments from the UFLS entities. The SPP UFLS Standard does not include duplicate requirements from the continent-wide standard to remove any confusion over a possible double jeopardy situation. The frequency setpoints for SPP's UFLS plan have not changed since the UFLS was originally created. None of the previous UFLS studies have indicated a need to alter from that approach. If the SPP system changes in the future and the UFLS study indicates a need to change the frequency setpoints, then SPP will change the Standard. SPP, as the Planning Coordinator, will adopt the SPP Regional Standard as the SPP UFLS Plan. The SPP System Protection and Control Working Group will review all exceptions that are brought to the Planning Coordinator.		
Salt River Project	No	

END OF REPORT

Exhibit E

NERC Record of Development of Proposed Regional Reliability Standard PRC-006-SPP-01

Regional Reliability Standards - Under Development				
Standard No.	**Title**	**Regional Status**	**Dates**	**NERC Status**
Southwest Power Pool, Inc. (SPP)				
PRC-006-SPP-01	Automatic Underfrequency Load Shedding	NERC Board Adopted November 7, 2012	08/15/12 - 09/28/12	Info **(1)** Submit Comments Comment Form **(2)** PRC-006-SPP-01 **(3)** Implementation Plan **(4)** Consideration of Comments **(5)**
			09/24/09	Monitoring Regional Progress

Regional Reliability Standards Announcement

Comment Period Open for PRC-006-SPP-01

August 15 – September 28, 2012

Regional Project: Now Available

Proposed Standard for the Southwest Power Pool (SPP)
SPP has requested NERC to post regional reliability standard **PRC-006-SPP-01 – SPP Automatic Underfrequency Load Shedding** for a 45-day industry review as permitted by the NERC Rules of Procedure. The comment period is open through **8 p.m. Eastern on Friday, September 28, 2012.**

Instructions
Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the regional reliability standards under development page.

Background
The SPP Automatic Underfrequency Load Shedding (UFLS) standard, PRC-006-SPP-01, was developed to provide regional UFLS requirements to entities in the SPP region. UFLS requirements have been in place at a continent-wide level and within SPP for many years prior to implementation of federally mandated reliability compliance standards in 2007.

When reliability standards were implemented, the Federal Energy Regulatory Commission (FERC), the government body with regulatory responsibility for electric reliability, issued FERC Order 693 recognizing 83 NERC Reliability Standards as enforceable by FERC and applicable to bulk power system users, owners, and operators. FERC did not approve the NERC UFLS standard, PRC-006-0, in Order 693. FERC's reason for not approving the standard was its recognition of PRC-006-0 as a "fill-in the blank standard," and because regional procedures associated with the standard were not submitted. FERC's ruling in Order 693 required Regional Entities to provide the regional requirements necessary for completing the UFLS standard.

In 2007, SPP began work on PRC-006-SPP-01. NERC also began revising its continent-wide UFLS standard; in May 2012, FERC approved NERC's PRC-006-1. The SPP standard is consistent with the NERC UFLS standard. PRC-006-1 clearly defines the roles and responsibilities of parties to whom the standard applies. PRC-006-1 identifies the Planning Coordinator (PC) as the entity responsible for developing UFLS schemes within its PC area. PRC-006-SPP-01 adds specificity not contained in the NERC standard for development and implementation of a UFLS scheme in the SPP Region that effectively mitigates the consequences of an underfrequency event.

Regional Reliability Standards Development Process

Section 300 of the Rules of Procedure for the Electric Reliability Organization governs the regional reliability 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 404-446-2560.

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Unofficial Comment Form for Regional Reliability Standard
PRC-006-SPP-01
SPP Automatic Underfrequency Load Shedding

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit comments on the Regional Reliability Standard **PRC-006-SPP-01** comments must be submitted by **8 p.m. Eastern on September 28, 2012.** If you have questions please contact Howard Gugel at howard.gugel@nerc.net or Barb Nutter at barbara.nutter@nerc.net.

Regional Reliability Standards Under Development Page

Background Information
A regional reliability standard shall be: (1) a regional reliability standard that is more stringent than the continent-wide reliability standard, including a regional standard that addresses matters that the continent-wide reliability standard does not; or (2) a regional reliability standard that is necessitated by a physical difference in the bulk power system. Regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. Regional reliability standards, when approved by FERC and applicable authorities in Mexico and Canada shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable area, regardless of membership in the region.

PRC-006-SPP-01 was developed to provide an adequate level of reliability for the bulk power system by implementing standards for UFLS programs that are specific to the SPP area.

Each **Southwest Power Pool (SPP)** Regional Reliability Standard shall enable or support one or more of the NERC reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk electric system. Each of those standards shall also be consistent with all of the NERC reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence. The NERC reliability principles supported by this standard are the following:

- **Reliability Principle 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.
- **Reliability Principle 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.
- **Reliability Principle 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.

The proposed SPP Regional Reliability Standard is not inconsistent with, or less stringent than established NERC Reliability Standards. Once approved by the appropriate authorities, the SPP Regional Reliability Standard obligates the SPP to monitor and enforce compliance, apply sanctions, if any, consistent with any regional agreements and the NERC rules.

R1. Each UFLS entity that has a total forecasted peak Load greater than or equal to 100 MW shall develop and implement an automatic UFLS program that meets the following requirements:

R2. Each UFLS entity that has a total forecasted peak Load less than 100 MW shall develop and implement an automatic UFLS program that meets the following requirements:

R3. Each UFLS entity electing to use underfrequency islanding schemes shall design those islanding schemes to operate after all 3 steps of UFLS have been exhausted and the frequency continues to fall to 58.5 Hz or below. For islanding schemes designed to operate at or between 58.5 Hz and 58.0 Hz, the minimum time delay shall be 2 seconds. For islanding schemes designed to operate below 58.0 Hz, no time delay is required.

R4. The Planning Coordinator shall perform and document a UFLS technical assessment within one year after the occurrence of any of the following situations:

R5. Each UFLS entity shall maintain and submit the following UFLS data based on the forecasted peak Load to the Planning Coordinator within (30) calendar days upon request from the Planning Coordinator:

R6. Each Generator Owner shall maintain and submit the following data to the Planning Coordinator within (30) calendar days upon request from the Planning Coordinator:

R7. Each Generator Owner shall verify that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2 as a result of the unit(s) frequency protective relay settings.

R8. The Planning Coordinator shall determine if the Generator Owner has provided technical evidence demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings.

R9. The Generator Owner or other UFLS entity(s) shall implement supplementary shedding of Load required by the Planning Coordinator in accordance with R8.1.1.

The approval process for a regional reliability standard requires NERC to publicly notice and request comment on the proposed standard. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

Unfair or Closed Process — The regional reliability standard was not developed in a fair and open process that provided an opportunity for all interested parties to participate. Although a NERC-approved regional reliability standards development procedure shall be presumed to be fair and open, objections could be raised regarding the implementation of the procedure.

Adverse Reliability or Commercial Impact on Other Interconnections — The regional reliability standard would have a significant adverse impact on reliability or commerce in other interconnections.

Deficient Standard — The regional reliability standard fails to provide a level of reliability of the bulk power system such that the regional reliability standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security.

Adverse Impact on Competitive Markets within the Interconnection — The regional reliability standard would create a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability.

1. **Do you agree the proposed standard is being developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

   ☐ Yes
   ☐ No

   Comments:

2. **Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

   ☐ Yes
   ☐ No

   Comments:

3. **Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?**

   ☐ Yes
   ☐ No

   Comments:

4. Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

☐ Yes

☐ No

Comments:

5. Does the proposed regional reliability standard meet at least one of the following criteria?

- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

☐ Yes

☐ No

Comments:

Introduction

1. **Title:** Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding

2. **Number:** PRC-006-SPP-01

3. **Purpose:** To develop, coordinate and document 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 Coordinator

   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. Generator Owners

5. **Effective Date:** Requirements R4, R5, and R6 shall become effective the first day of the first calendar quarter one year after regulatory approval.

   The remaining requirements shall become effective the first day of the first calendar quarter three years after regulatory approval.

6. **Basis for Standard Development:** UFLS entity's planning data for the upcoming calendar year.

UFLS program performance will be measured based on the entity's planning values and not the one-minute average of the entity's load prior to the first underfrequency relay action. This has changed from the current SPP Criteria.

Requirements and Measures

R1. Each UFLS entity that has a total forecasted peak Load greater than or equal to 100 MW shall develop and implement an automatic UFLS program that meets the following requirements: [VRF: High][Time Horizon: Long-term Planning]

1.1. A minimum of 10% shall be shed at each UFLS step in accordance with the table below.

(1) UFLS Step	(2) Frequency (hertz)	(3) Minimum accumulated load relief as percentage of forecasted peak Load (%)	(4) Maximum accumulated load relief as percentage of forecasted peak Load (%)
1	59.3	10	25
2	59.0	20	35
3	58.7	30	45

1.2. The intentional relay time delay for UFLS shall be less than or equal to 30 cycles.

1.3. Undervoltage inhibit setting shall be less than or equal to 85 percent of nominal voltage.

M1. Each UFLS entity shall have evidence such as reports, program plans, or other documentation of its UFLS program that demonstrates it meets requirement R1 Parts 1.1 through 1.3.

The current SPP UFLS program includes three separate UFLS steps with a minimum load shedding percentage of 10%, 20%, and 30%, cumulatively, for each of the three steps. These have remained unchanged from the SPP Criteria. The SDT believed that it was reasonable to increase the maximum load shedding percentages in steps 1 and 2. The maximum load shedding percentages in steps 1 and 2 were increased from 15% and 30%, respectively, to 25% and 35%, allowing more flexibility for those steps.

Total forecasted peak Load is the projected planning value of an entity's end-use customers' coincident system peak load for the upcoming calendar year.

R2. Each UFLS entity that has a total forecasted peak Load less than 100 MW shall develop and implement an automatic UFLS program that meets the following requirements: [VRF: Medium][Time Horizon: Long-term Planning]

2.1. A minimum of one UFLS step with the frequency set point as assigned by the Planning Coordinator.

2.2. The minimum accumulated Load relief shall be at least 30% of the forecasted peak Load.

2.3. The intentional relay time delay for UFLS shall be less than or equal to 30 cycles.

2.4. Undervoltage inhibit setting shall be less than or equal to 85 percent of nominal voltage.

M2. Each UFLS entity shall have evidence such as reports, program plans, or other documentation of its UFLS program that demonstrates it meets requirement R2 Parts 2.1 through 2.4.

The SDT realized that some small UFLS entities may experience difficulty in achieving more than one UFLS step due to a smaller arrangement of loads and meeting the tolerances set forth in the load shedding table of R1.1. The basis for selecting 100 MW as the threshold comes from the use of this same value in other regional UFLS standards and a reasonable judgment that the total forecasted load served by most smaller electric utilities is less than 100 MW. R2 was structured to accommodate these small entities and its inclusion within this standard indicates the importance of having all entities participate in the UFLS program.

R3. Each UFLS entity electing to use underfrequency islanding schemes shall design those islanding schemes to operate after all 3 steps of UFLS have been exhausted and the frequency continues to fall to 58.5 Hz or below. For islanding schemes designed to operate at or between 58.5 Hz and 58.0 Hz, the minimum time delay shall be 2 seconds. For islanding schemes designed to operate below 58.0 Hz, no time delay is required. [VRF: Lower][Time Horizon: Long-term Planning]

M3. Each UFLS entity electing to use islanding schemes shall have evidence such as reports, program plans, or other documentation of its UFLS program that demonstrates it meets requirement R3.

UFLS entities may elect to implement schemes following operation of all three underfrequency steps should the frequency continue to decay. The SDT believes that a time delay on initiation of islanding for frequencies slightly below the third step of load shedding is necessary to allow time for system recovery and to accommodate some frequency overshoot. The SPP UFLS study, conducted by Powertech, showed that frequency excursions between 58.5 and 58.0 Hz would recover in less than 2 seconds. Therefore, having a 2 second time delay may avoid islanding.

This Requirement does not include Out-of-Step trip relaying designed to isolate portions of the power grid for unstable power swings.

R4. The Planning Coordinator shall perform and document a UFLS technical assessment within one year after the occurrence of any of the following situations: [VRF: Medium][Time Horizon: Long-term Planning]

- Performance characteristic changes to PRC-006 or the SPP UFLS standard.
- Changes to the boundaries of a specified island are identified.

M4. The Planning Coordinator shall have evidence that it performed a technical assessment per requirement R4.

Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS is required by NERC PRC-006-0 R1.3 to be conducted periodically (at least every five years or required by changes in system conditions). The purpose of the SPP UFLS requirement R4 is to expand upon NERC PRC-006-0 R1.3. "Changes in system conditions" includes performance characteristic changes in PRC-006 or this SPP UFLS document. This also includes changes to the boundaries of a specified island, for example when Nebraska was brought into the SPP specified island. The SDT believes after such changes it is imperative to perform a new assessment to ensure UFLS program effectiveness.

R5. Each UFLS entity shall maintain and submit the following UFLS data based on the forecasted peak Load to the Planning Coordinator within (30) calendar days upon request from the Planning Coordinator: [VRF: Lower][Time Horizon: Long-term Planning]

5.1. Location of installed UFLS equipment

5.2. Trip frequency(s) for each location

5.3. Total relay operating time of each location (time required for the relay to reliably sense the frequency + intentional delay time (if any))

5.4. Breaker operating time (nameplate) of each location

5.5. Percentage and/or MW of bus load to be shed at the location

5.6. Total amount of load shed by each trip frequency and the total forecasted peak Load

5.7. Tie tripping schemes and the frequency and time delay at which they operate

5.8. Islanding schemes and the frequency and time delay at which they operate

M5. Each UFLS entity shall have evidence that the information was supplied to the Planning Coordinator per requirement R5.

The NERC standard requires that; "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." The information requested in R5 is the data required by the Planning Coordinator to model the UFLS program and maintain compliance to the NERC standard.

R6. Each Generator Owner shall maintain and submit the following data to the Planning Coordinator within (30) calendar days upon request from the Planning Coordinator: [VRF: Lower][Time Horizon: Long-term Planning]

6.1. Location of underfrequency and overfrequency equipment

6.2. Trip frequency(s) for each location

6.3. Total relay operating time of each location (time required for the relay to reliably sense the frequency + intentional delay time (if any))

6.4. Breaker operating time (nameplate) of each location

6.5. MW of generation shed at each location

M6. Each Generator Owner shall have evidence that the information was supplied to the Planning Coordinator per requirement R6.

The SDT believes this generator data is needed by the Planning Coordinator for the following reasons:
1.) better modeling for UFLS technical assessments,
2.) performing routine UFLS studies, and
3.) post-event analysis.

This data will enable the Planning Coordinator to evaluate whether the generator can meet the R7 requirement and determine if additional load shedding is required on the part of the UFLS entities.

R7. Each Generator Owner shall verify that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2 as a result of the unit(s) frequency protective relay settings. [VRF: Medium][Time Horizon: Long-term Planning]

7.1. For generating units with operating characteristics that limit the unit's ability to perform in accordance with R7, the Generator Owner shall provide to the Planning Coordinator technical evidence demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings.

M7. Each Generator Owner shall have evidence that it complies with R7 or that the information was supplied to the Planning Coordinator, if appropriate, as required in R7.1.

In order to effectively study and evaluate the performance of the UFLS system the generator relay protection trip values must be known. The ultimate goal is to balance the generation and load so that a total collapse does not occur. Therefore, the generator trip values are critical to evaluating the performance of the UFLS system. With this information the system can then be studied.

R8. The Planning Coordinator shall determine if the Generator Owner has provided technical evidence demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings. [VRF: Medium][Time Horizon: Long-term Planning]

8.1. The Planning Coordinator shall determine if the UFLS program performance is degraded due to the removal of any generation identified in accordance with R7.1 and verified in accordance with R8.

8.1.1. If the Planning Coordinator determines the UFLS program is degraded in accordance with R8.1 and that supplementary load shedding is, therefore, required, the Planning Coordinator shall notify the Generator Owner or UFLS entity(s) in accordance with the following:

- Where the Generator Owner is a UFLS Entity and has the required amount of supplementary Load available, the Planning Coordinator shall notify the Generator Owner of Load the entity is required to shed (in addition to that required in accordance with R1 and R2)

- Where the Generator Owner is not a UFLS Entity, or does not have the required supplementary Load available for shedding, the Planning Coordinator shall notify any other UFLS Entity(s) within the Planning Coordinator Area of Load the entity(s) is required to shed (in addition to that required in accordance with R1 and R2)

M8. The Planning Coordinator shall have evidence that it complies with the requirements in R8.

The Planning Coordinator is required to verify the Generator Owner's technical justification for not being able to operate throughout the Attachment 1 and 2 curves and to review the consequences to the UFLS program performance for the loss of that additional generation after the initiation of an under frequency event. It also provides a mechanism for the Planning Coordinator to resolve the detrimental effects of the loss of this additional generation if it determines that the performance of the UFLS program is degraded.

R9. The Generator Owner or other UFLS entity(s) shall implement supplementary shedding of Load required by the Planning Coordinator in accordance with R8.1.1. [VRF: Medium][Time Horizon: Long-term Planning]

M9. The Generator Owner or other UFLS entity shall have evidence that it complies with the requirements in R9.

The SDT's decision to include R9 is to prevent blackouts caused by early removal of generating units from the system. In a real time load shedding event, if the UFLS is degraded in accordance with R8.1.1, removal of units will make the system condition worse. This is the main reason for the supplementary shedding of loads to compromise the loss of generation. This action is critical to bring back the unstable system to stable.

Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

SPP Regional Entity
SERC (for Planning Coordinator only)

1.2. Data Retention

The Planning Coordinator and each UFLS entity and Generator Owner shall keep data or dated evidence to show compliance as identified below unless directed by SPP Regional Entity to retain specific evidence for a longer period of time as part of an investigation:

- Each UFLS entity shall retain the current evidence of Requirements R1 or R2, and R3, Measures M1 or M2, and M3, as well as any evidence necessary to show compliance since the last compliance audit.

- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator since the last compliance audit in accordance with Requirement R5, Measure M5.

- The Planning Coordinator shall retain the current evidence of Requirement R4, Measure M4 as well as any evidence necessary to show compliance since the last compliance audit.

- Each Generator Owner shall retain evidence of UFLS data transmittal to the Planning Coordinator since the last compliance audit in accordance with Requirement R6, Measure M6.

- Each Generator Owner shall retain evidence of Requirements R7, Measures M7 as well as any evidence necessary to show compliance since the last compliance audit.

If the Planning Coordinator, UFLS entity or Generator Owner 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.

1.3. Compliance Monitoring and Assessment Process

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

1.4. Additional Compliance Information

UFLS entities may implement an aggregated UFLS program with other UFLS entities. In R1 and R2, the 100 MW limit refers to the aggregated UFLS program, if one exists.

2. Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Long-Term Planning	High	N/A	UFLS entity developed a program, but failed to meet any one (1) of the following 5 requirements: Part 1.1 (Step1-3) Part 1.2 Part 1.3	UFLS entity developed a program, but failed to meet any two (2) of the following 5 requirements: Part 1.1 (Step1-3) Part 1.2 Part 1.3	UFLS entity developed a program, but failed to meet three (3) or more of the following 5 requirements: Part 1.1 (Step1-3) Part 1.2 Part 1.3 OR Failed to develop a UFLS program
R2	Long-Term Planning	Medium	UFLS entity developed a program, but failed to meet one (1) of the requirements in Parts 2.1 through 2.4	UFLS entity developed a program, but failed to meet two (2) of the requirements in Parts 2.1 through 2.4	UFLS entity developed a program, but failed to meet three (3) of the requirements in parts 2.1 through 2.4	UFLS entity developed a program, but failed to meet all four (4) of the requirements in Parts 2.1 through 2.4 OR Failed to develop a UFLS program

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R3	Long-Term Planning	Lower	N/A	N/A	N/A	UFLS entity, electing to use underfrequency islanding schemes, failed to develop an islanding scheme per the requirement
R4	Long-Term Planning	Medium	The Planning Coordinator performed a technical assessment within five years and three months or within one year and three months after one of the situations listed in R4	The Planning Coordinator performed a technical assessment within five years and six months or within one year and six months after one of the situations listed in R4	The Planning Coordinator performed a technical assessment within five years and nine months or within one year and nine months after one of the situations listed in R4	The Planning Coordinator performed a technical assessment within six years or within two years after one of the situations listed in R4 OR The Planning Coordinator failed to perform a technical assessment
R5	Long-Term Planning	Lower	UFLS entity provided required data more than 30 calendar days and up to and including 45 calendar days following the request	UFLS entity provided required data more than 45 calendar days and up to and including 60 calendar days following the request OR UFLS entity did not provide one piece of information listed in R5	UFLS entity provided required data more than 60 calendar days and up to and including 75 calendar days following the request OR UFLS entity did not provide two pieces of	UFLS entity provided required data more than 75 calendar days following the request OR UFLS entity did not provide required data after the request was

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
				(e.g., 5.1.)	information listed in R5 (e.g., 5.1. and 5.2.)	made OR UFLS entity did not provide three or more pieces of information listed in R5 (e.g., 5.1. and 5.2. and 5.3.)
R6	Long-Term Planning	Lower	Generator Owner provided required data more than 30 calendar days and up to and including 45 calendar days following the request	Generator Owner provided required data more than 45 calendar days and up to and including 60 calendar days following the request OR Generator Owner did not provide one piece of information listed in R6 (e.g., 6.1.)	Generator Owner provided required data more than 60 calendar days and up to and including 75 calendar days following the request OR Generator Owner did not provide two pieces of information listed in R6 (e.g., 6.1. and 6.2.)	Generator Owner provided required data more than 75 calendar days following the request OR Generator Owner did not provide required data after the request was made OR Generator Owner did not provide three or more pieces of information listed in R6 (e.g., 6.1. and 6.2. and 6.3.)

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R7	Long-Term Planning	Medium	N/A	N/A	The Generator Owner did not provide technical evidence to the Planning Coordinator demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings for their generating units with operating characteristics that limit the unit's ability to perform in accordance with R7.	The Generator Owner did not verify that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2 due to the generator unit frequency protective relay settings.
R8	Long-Term Planning	Medium	N/A	N/A	The Planning Coordinator determined that the UFLS program was degraded in accordance with R8.1, but did not notify the Generator Owner or the UFLS entity of the Load that they were required to	The Planning Coordinator did not determine if the UFLS program performance was degraded due to the removal of any generation identified in accordance with R7.1 and verified in accordance with R8.

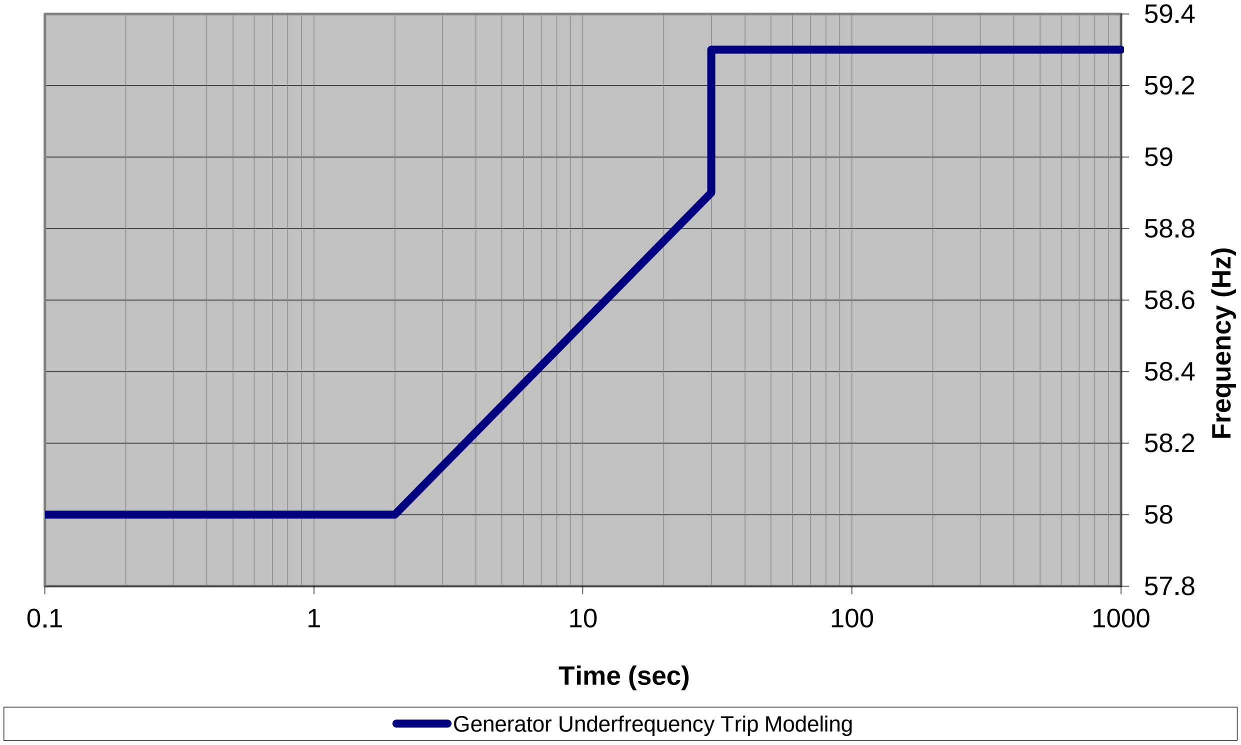
R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
					shed.	
R9	Long-Term Planning	Medium	N/A	N/A	N/A	The Generator Owner or other UFLS entity did not implement supplementary shedding of Load required by the Planning Coordinator in accordance with R8.1.1.

B. Associated Documents

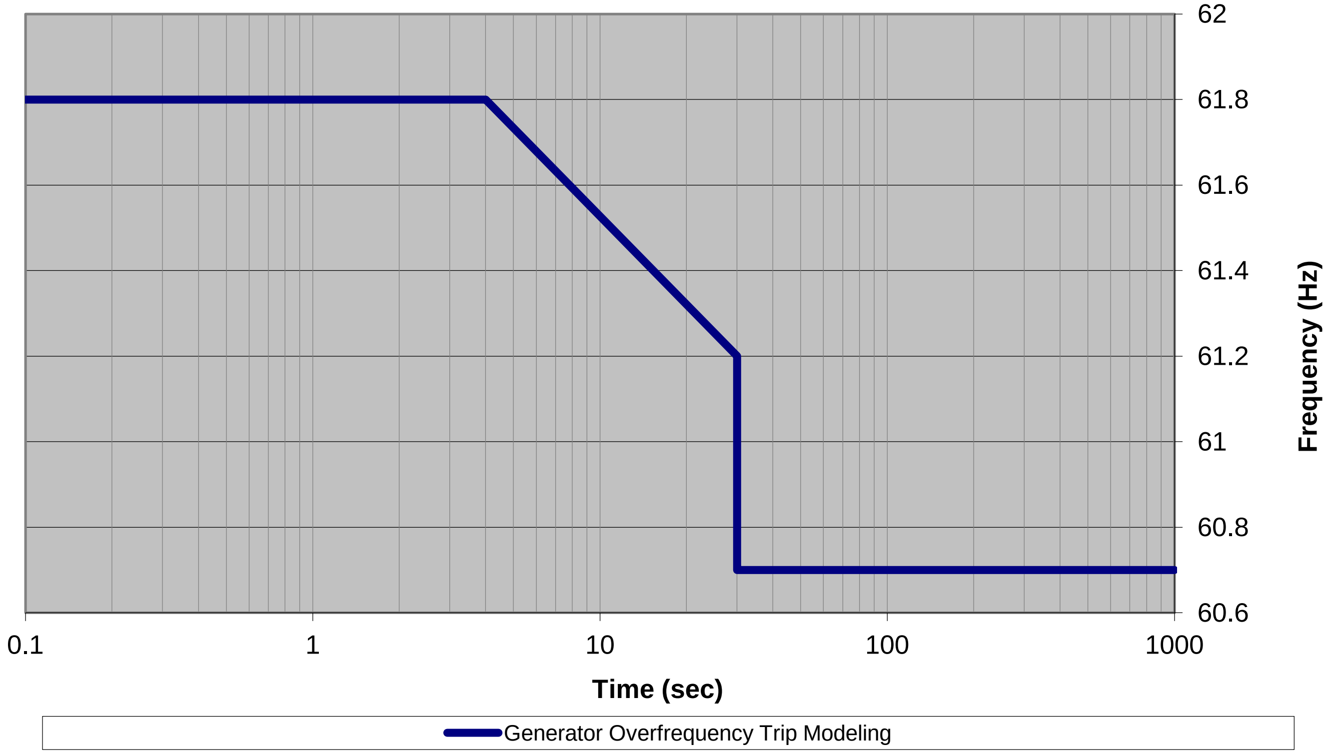
Version History

Version	Date	Action	Change Tracking
Draft 1	3/31/2009 thru 4/30/2009	Posted for 1st Comment Period	Initial version
Draft 2	8/31/2009 thru 9/30/2009	Posted for 2nd Comment Period	Revised to address comments from Draft 1
Draft 3	3/29/2010 thru 4/28/2010	Posted for 3rd Comment Period	Revised to address comments from Draft 2
Draft 4	12/18/2010 thru 1/7/2011	Posted for 4th Comment Period	Revised to address comments from Draft 3
Draft 5	1/18/2011	Posted for 1st Open Vote	Revised to address comments from Draft 4
Draft 6	6/10/2011 thru 7/10/2011	Posted for 6th Comment Period	Revised to address comments from Draft 5
Draft 7	9/30/2011	Posted for 2nd Open Vote	Revised to address comments from Draft 6 and changed to results-based format

PRC-006-SPP-1 - Attachment 1
Underfrequency Curves for Requirement R7



PRC-006-SPP-1 - Attachment 2
Overfrequency Curves for Requirement R7



Implementation Plan for SPP Underfrequency Load Shedding, PRC-006-SPP-01

Prerequisite Approvals

SPP Regional Entity Trustees

Proposed Effective Date

Requirements R4, R5, and R6 shall become effective the first day of the first calendar quarter one year after regulatory approval. The one year phase in for compliance is needed for the Planning Coordinator to perform the studies necessary to assess the effectiveness of the UFLS program.

The remaining requirements shall become effective the first day of the first calendar quarter three years after regulatory approval. The additional two year phase in for compliance is needed for any necessary changes to be made to the existing UFLS schemes.

Applicability

The entities listed in the Applicability section will be held responsible for their requirements according to the effective dates listed above.

Field Testing

None

Other Considerations

UFLS entities may implement an aggregated UFLS program with other UFLS entities. In R1 and R2, the 100 MW limit refers to the aggregated UFLS program, if one exists.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Regional Reliability Standard PRC-006-SPP-01

The Regional Reliability Standard PRC-006-SPP-01 Drafting Team thank all commenters who submitted comments on the Regional Reliability Standard **PRC-006-SPP-01**. This standard was posted for a 45-day public comment period from August 15, 2012 through September 28, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 10 sets of comments, including comments from more than 11 different people from approximately 10 companies representing 6 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

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 of Standards, Mark Lauby , at 404-446-2560 or via e-mail at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Vassallo	BPA, Transmission	WECC	1

2.	Individual	Jake Rice	City Water & Light			X							
3.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
4.	Individual	Tiffany Lake	Westar Energy	X		X		X	X				
5.	Individual	Gary Cox	Southwestern Power Administration	X								X	
6.	Individual	Doug Peterchuck	Omaha Public Power District	X		X		X	X				
7.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
8.	Individual	Alice Ireland	Southwestern Public Service Company, an Xcel Energy company	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Individual	Thad Ness	American Electric Power	X		X		X	X				
10.	Individual	Mayor Mark Piazza	City of Abbeville	X					X		X		

1. **Do you agree the proposed standard is being developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	Yes	
City Water & Light	Yes	
Salt River Project	Yes	
Westar Energy	Yes	
Southwestern Power Administration	Yes	
Southwestern Public Service Company, an Xcel Energy company	Yes	
American Electric Power	Yes	
City of Abbeville	Yes	
Omaha Public Power District	No	SPP's weighting structure allowed for a single vote to carry the complete weight of one of their five segments, (20%). Additionally, companies that qualify for more than one segment were only permitted to vote in one of the segments, rather than all that they were qualified to vote in. As chance would have it, only one of the SPP BA/TOP members cast their vote as a "Marketer/Broker" (of which many SPP members qualify for) and thus was

Organization	Yes or No	Question 1 Comment
		able to control the entire segment, i.e. 20% of the overall vote. If that vote were cast as negative or not cast at all, the regional standard would not have passed with the SPP membership. SPP membership companies' associates were also permitted to vote in the "End User and Public Interest" segment and thus able to control that segment as well (20%). It was explained that any individual, even those that work for a SPP membership company and/or those individuals participating on the Standard Drafting Team, are permitted to vote in the End User segment in addition to their company's vote. This "loophole" permits a company to vote 2, 3 or even 200+ times. The previously described 2 segments included only 5 total votes. These 2 segments unanimously approved the Regional Standard. However the 3 segments that will be directly affected by the approval of this Regional Standard were adamantly opposed to its approval having voted as follows: Transmission (53%), Generation (71%), Distribution/LSE (53%). These 3 segments cast 36 votes, or 88% of the total votes cast on this Regional Standard.

Response: The proposed PRC-006-SPP-01 Under Frequency Load Shedding Standard (PRC-006-SPP-01) was developed in a fair and open process, using the NERC and FERC-approved Southwest Power Pool Regional Entity Standards Development Process Manual (SPP RE Manual). Contrary to OPPD's assertion, "the 3 segments that will be directly affected by the approval of this Regional Standard" were not adamantly opposed to PRC-006-SPP-01; all five voting segments, not just the End User and Marketer/Broker segments, voted in the majority for approval of PRC-006-SPP-01. A Standards Process Manual Task Force (SPMTF) has been established to identify and propose revisions (RSR-002: Proposed Revision 1 – SPP Regional Entity Standard Development Process Manual) to appropriately address questions and concerns raised during the initial implementation of the SPP RE Manual.

The SPP RE Manual provides:

1. "An interested party may only register in one segment." (Section V, Step 5, SPP Segment Weighted Voting, pg 15. Also see 119 FERC 61,060, Paragraph 418, pg. 134 in which FERC stated "We clarify that we expect SPP to follow a one-entity/one-vote policy.")

Organization	Yes or No	Question 1 Comment

2. "Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the Bulk Power System has a right to participate by: a) expressing a position and its basis, b) having that position considered, c) voting on a proposed regional reliability standard through a segment weighted balanced process, and d) having the right to appeal." (Introduction, pg 3).

3. "Votes will be counted by voting segment. Each voting segment will receive 20% of the vote." (Section V, Step 5, SPP Segment Weighted Voting, pg 15)

4. "The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. In all cases, the request for appeal must be made prior to the next step in the process." (Appendix A, II. Appeals, pg. 19)[2]

Persons, organizations, companies, government agencies, and individuals were allowed to participate in development of PRC-006-SPP-01, including voting on the proposed standard. All UFLS Standard Drafting Team (SDT) meetings were open and posted on SPP's public website, and the SDT provided reports to numerous Market and Operations Policy Committee and Regional Entity Trustee meetings. As required by the SPP RE Manual and the FERC order, entities were allowed to register and vote in only one segment. In determining the voting results, each of the voting segments received equal (20%) weighting. (Unlike the NERC Registered Ballot Body Criteria, the SPP RE Manual does not include any provisions that prohibit employees of organizations or companies from also registering and voting on proposed standards; nor does the SPP RE Manual include any provisions that allow for a proportional reduction in the weight given to segments that have a limited number votes.)

Regarding the registered ballot body voting results, all five of the segments had a majority affirmative vote: 53% voted yes in Transmission, 71% voted yes in Generation, 100% voted yes in Marketer/Broker, 53% voted yes in Distribution/LSE, and 100% voted yes in End User/Public Interest. These affirmative majorities do not indicate that any segments "were adamantly opposed."

Consistent with SPP's core value of continuous improvement, SPP RE is addressing stakeholder's concerns regarding segment weighting, segment qualifications, and "one entity one vote" through the Standards Process Manual Task Force (SPMTF). The SPMTF is

[2] Although OPPD requested clarification regarding SPP RE's determination of the voting results, it did not submit any appeals to any actions regarding PRC-006-SPP-01 development or balloting.

Organization	Yes or No	Question 1 Comment
serving as the Standard Drafting Team for revising the SPP RE Manual; all stakeholders who asked to serve on the SPMTF, including representatives from OPPD and LES, were appointed.		
Lincoln Electric System	No	SPP's weighting structure allowed for a single vote to carry the complete weight of one of their five segments, (20%). Additionally, companies that qualify for more than one segment were only permitted to vote in one of the segments, rather than all that they were qualified to vote in. As chance would have it, only one of the SPP BA/TOP members cast their vote as a "Marketer/Broker" (of which many SPP members qualify for) and thus was able to control the entire segment, i.e. 20% of the overall vote. If that vote were cast as negative or not cast at all, the regional standard would not have passed with the SPP membership. SPP membership companies' associates were also permitted to vote in the "End User and Public Interest" segment and thus able to control that segment as well (20%). It was explained that any individual, even those that work for a SPP membership company and/or those individuals participating on the Standard Drafting Team, are permitted to vote in the End User segment in addition to their company's vote. This "loophole" permits a company to vote 2, 3 or even 200+ times.The previously described 2 segments included only 5 total votes! These 2 segments unanimously approved the Regional Standard. However the 3 segments that will be directly affected by the approval of this Regional Standard were adamantly opposed to its approval having voted as follows: Transmission (53%), Generation (71%), Distribution/LSE (53%). These 3 segments cast 36 votes, or 88% of the total votes cast on this Regional Standard.
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Organization	Yes or No	Question 1 Comment

to identify and propose revisions (RSR-002: Proposed Revision 1 – SPP Regional Entity Standard Development Process Manual) to appropriately address questions and concerns raised during the initial implementation of the SPP RE Manual.

The SPP RE Manual provides:

5. "An interested party may only register in one segment." (Section V, Step 5, SPP Segment Weighted Voting, pg 15. Also see 119 FERC 61,060, Paragraph 418, pg. 134 in which FERC stated "We clarify that we expect SPP to follow a one-entity/one-vote policy.")

6. "Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the Bulk Power System has a right to participate by: a) expressing a position and its basis, b) having that position considered, c) voting on a proposed regional reliability standard through a segment weighted balanced process, and d) having the right to appeal." (Introduction, pg 3).

7. "Votes will be counted by voting segment. Each voting segment will receive 20% of the vote." (Section V, Step 5, SPP Segment Weighted Voting, pg 15)

8. "The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. In all cases, the request for appeal must be made prior to the next step in the process." (Appendix A, II. Appeals, pg. 19)[3]

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[3] Although Lincoln Electric System requested clarification regarding SPP RE's determination of the voting results, it did not submit any appeals to any actions regarding PRC-006-SPP-01 development or balloting.

Organization	Yes or No	Question 1 Comment
Manual does not include any provisions that prohibit employees of organizations or companies from also registering and voting on proposed standards; nor does the SPP RE Manual include any provisions that allow for a proportional reduction in the weight given to segments that have a limited number votes.) Regarding the registered ballot body voting results, all five of the segments had a majority affirmative vote: 53% voted yes in Transmission, 71% voted yes in Generation, 100% voted yes in Marketer/Broker, 53% voted yes in Distribution/LSE, and 100% voted yes in End User/Public Interest. These affirmative majorities do not indicate that any segments "were adamantly opposed." Consistent with SPP's core value of continuous improvement, SPP RE is addressing stakeholder's concerns regarding segment weighting, segment qualifications, and "one entity one vote" through the Standards Process Manual Task Force (SPMTF). The SPMTF is serving as the Standard Drafting Team for revising the SPP RE Manual; all stakeholders who asked to serve on the SPMTF, including representatives from OPPD and LES, were appointed.		

2. **Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

Summary Consideration:

Organization	Yes or No	Question 2 Comment
Omaha Public Power District	Yes	This SPP project was initiated on 10/29/07 with the completion of a SPP Regional Standard Request Form. As stated in that form, the objective of the project was to meet the requirements of the NERC PRC-006-0 “Fill in the Blank” UFLS standard. The goal of the project was to take the SPP RTO UFLS Criteria and transform it into a SPP RE Regional standard. Note, in 2007 the SPP RE and SPP RTO boundaries aligned. In 2009, the Nebraska entities joined the SPP RTO, however as NE’s RTO membership changes have no bearing on our RE compliance associations the SPP RE and SPP RTO boundaries no longer align. In general, a UFLS program should cover the entire RTO, or more specifically, the Planning Coordinator footprint, however approving this SPP RE Regional Standard will prohibit this. In only 2 of the 8 NERC RE Regions do the RE boundaries align with the RTO boundaries, thus it makes little sense to develop a UFLS program on a RE footprint basis as was originally required in the PRC-006-0 (version zero) standard. NERC recognized this fact and has assigned the responsibility of developing a UFLS program to the Planning Coordinators, i.e. the SPP RTO, in the new continent-wide NERC standard PRC-006-1. FERC also agrees with this approach as is evident in their NOPR to approve PRC-006-1 which the Commission filed on October 20, 2011 (Docket No. RM11-20-000). Within Paragraph 46 of this Order FERC states:Requirement R2.3 allows Planning Coordinators to “adjust the island boundaries to differ from the Regional Entity area boundaries by mutual consent where necessary” to preserve contiguous island boundaries that better reflect simulations. The Commission agrees that identifying island boundaries based on where they are likely to occur due to system characteristics, as opposed to

Organization	Yes or No	Question 2 Comment
		maintaining rigid Regional Entity area boundaries, should result in more effective UFLS programs. Accordingly, the Commission encourages cooperation among entities to create UFLS programs that set island boundaries based on where separations are expected to occur during an under frequency event.The proposed SPP RE regional standard assigns the responsibility of creating a UFLS program to the "UFLS Entities" (Transmission Owners and Distribution Providers) which contradicts with NERC's and FERC's belief that a UFLS program should be developed by the Planning Coordinator. It should be noted that currently within the SPP RE footprint there are 53 registered Distribution Providers and 40 registered Transmission Owners. We do not believe many of these small TOs and DPs are in any position to develop a UFLS program as required by R1 and R2 of the proposed SPP RE standard, nor do they have the wide area view necessary to set up islanding schemes as required in R3 of the SPP RE standard.Additionally, the SPP RE regional standard is in direct conflict with NERC's PRC-006-1 standard. The NERC approved standard requires the SPP Planning Coordinator to create a UFLS program, however the SPP RE standard requires all of the UFLS entities to create a program. As written, the SPP RE UFLS entities will have 2 programs to follow, the Planning Coordinator's and their own. Also, some of the Requirements (R4 and R5) in the proposed SPP RE standard are duplicative of the NERC standard and therefore are not needed in the Regional Standard. As mentioned above, Nebraska entities will not fall under this regional requirement, as NPPD, OPPD, and LES are individually registered with the MRO. It is a concern of the Nebraska entities that if and when the SPP RTO (Planning Coordinator for the Nebraska Entitites) leans on the regional UFLS standard as the "PC UFLS Plan", gaps in compliance and reliability will exist. Without a formal PC UFLS plan, Nebraska entities will not be able to meet compliance with the continent wide PRC-006-1 standard.
Response: NERC PRC-006 is not applicable to Generator Owners. The only way to enforce the Generator Owners' participation in the UFLS program is to create a Regional Standard. The SPP UFLS SDT believes that the UFLS program needs to include Generator Owners since they have an essential part in balancing load and generation. PRC-024-1 is a NERC standard under development that will ensure that generating units remain connected during frequency excursions and ensure expected generating unit performance during		

Organization	Yes or No	Question 2 Comment
frequency excursions is communicated to the RC, PC, TOP, and TP for accurate system modeling. The Regional Standard approach would require all SPP RE registered entities in the SPP footprint to be held applicable to the SPP Regional Standard; this would include all NERC Registered Entities in the SPP Region. With only the NERC PRC-006 program approach, only those entities for which the SPP RTO is the Planning Coordinator would be held accountable to the UFLS program. Non-SPP members that are in the SPP RE footprint would not be held accountable to the UFLS program and thus would be required to develop their own or have another Planning Coordinator include them in their program. If SPP, as the Planning Coordinator, is responsible for the reliability of the SPP footprint, then SPP needs the authority of a Regional Standard to fulfill its responsibility. R3 does not require UFLS entities to utilize an islanding scheme. UFLS entities can elect to choose an islanding scheme. R4 and R5 are not duplicative of the NERC standard. The SPP Regional Standard contains requirements that are more stringent than the NERC standard.		
Lincoln Electric System	Yes	This SPP project was initiated on 10/29/2007 with the completion of a SPP Regional Standard Request Form. As stated in that form, the objective of the project was to meet the requirements of the NERC PRC-006-0 “Fill in the Blank” UFLS standard. The goal of the project was to take the SPP RTO UFLS Criteria and transform it into a SPP RE Regional standard. Note, in 2007 the SPP RE and SPP RTO boundaries aligned. In 2009, the Nebraska entities joined the SPP RTO, however as NE’s RTO membership changes have no bearing on our RE compliance associations the SPP RE and SPP RTO boundaries no longer align. In general, a UFLS program should cover the entire RTO, or more specifically, the Planning Coordinator footprint, however, approving this SPP RE Regional Standard will prohibit this. In only 2 of the 8 NERC RE Regions do the RE boundaries align with the RTO boundaries, thus it makes little sense to develop a UFLS program on a RE footprint basis as was originally required in the PRC-006-0 (version zero) standard. NERC recognized this fact and has assigned the responsibility of developing a UFLS program to the Planning Coordinators, i.e. the SPP RTO, in the new continent-wide NERC standard PRC-006-1. FERC also agrees with this approach as is evident in their NOPR to approve PRC-006-1 which the Commission filed on

Organization	Yes or No	Question 2 Comment
		October 20, 2011 (Docket No. RM11-20-000). Within Paragraph 46 of this Order FERC states:"Requirement R2.3 allows planning coordinators to “adjust the island boundaries to differ from the Regional Entity area boundaries by mutual consent where necessary” to preserve contiguous island boundaries that better reflect simulations. The Commission agrees that identifying island boundaries based on where they are likely to occur due to system characteristics, as opposed to maintaining rigid Regional Entity area boundaries, should result in more effective UFLS programs. Accordingly, the Commission encourages cooperation among entities to create UFLS programs that set island boundaries based on where separations are expected to occur during an under frequency event."The proposed SPP RE regional standard assigns the responsibility of creating a UFLS program to the “UFLS Entities” (Transmission Owners and Distribution Providers) which contradicts with NERC’s and FERC’s belief that a UFLS program should be developed by the Planning Coordinator. It should be noted that currently within the SPP RE footprint there are 53 registered Distribution Providers and 40 registered Transmission Owners. We do not believe many of these small TOs and DPs are in any position to develop a UFLS program as required by R1 and R2 of the proposed SPP RE standard, nor do they have the wide area view necessary to set up islanding schemes as required in R3 of the SPP RE standard.Additionally, the SPP RE regional standard is in direct conflict with NERC’s PRC-006-1 standard. The NERC approved standard requires the SPP Planning Coordinator to create a UFLS program, however the SPP RE standard requires all of the UFLS entities to create a program. As written, the SPP RE UFLS entities will have 2 programs to follow, the Planning Coordinator’s and their own. Also, some of the Requirements (R4 and R5) in the proposed SPP RE standard are duplicative of the NERC standard and therefore are not needed in the Regional Standard.
Response: NERC PRC-006 is not applicable to Generator Owners. The only way to enforce the Generator Owners’ participation in the UFLS program is to create a Regional Standard. The SPP UFLS SDT believes that the UFLS program needs to include Generator Owners since they have an essential part in balancing load and generation. PRC-024-1 is a NERC standard under development that will ensure that generating units remain connected during frequency excursions and ensure expected generating unit performance during frequency excursions is communicated to the RC, PC, TOP, and TP for accurate system modeling.		

Organization	Yes or No	Question 2 Comment
The Regional Standard approach would require all SPP RE registered entities in the SPP footprint to be held applicable to the SPP Regional Standard; this would include all NERC Registered Entities in the SPP Region. With only the NERC PRC-006 program approach, only those entities for which the SPP RTO is the Planning Coordinator would be held accountable to the UFLS program. Non-SPP members that are in the SPP RE footprint would not be held accountable to the UFLS program and thus would be required to develop their own or have another Planning Coordinator include them in their program. If SPP, as the Planning Coordinator, is responsible for the reliability of the SPP footprint, then SPP needs the authority of a Regional Standard to fulfill its responsibility. R3 does not require UFLS entities to utilize an islanding scheme. UFLS entities can elect to choose an islanding scheme. R4 and R5 are not duplicative of the NERC standard. The SPP Regional Standard contains requirements that are more stringent than the NERC standard.		
City Water & Light	No	Not to our knowledge.
Response: Thank you for your comment.		
Southwestern Public Service Company, an Xcel Energy company	No	Southwestern Public Service Company is in favor of this proposed regional standard. While the standard as proposed helps clarify many issues, there are two areas that may need additional clarification. In Requirement 8, it is unclear what would constitute a technical basis for operating outside the specified frequency range. One would assume this request for exception from the requirements of the standard would be reviewed by a technically oriented group, and that the basis would have to consider many factors.In addition, under Requirement 8.1.1, the method that the Planning Coordinator would use to allocate additional load shed to other UFLS entities in the event that a Generator Owner does not have supplementary load for shedding is unclear. This could place a disproportionate responsibility for shedding load on customers of other UFLS entities, without compensation or recourse.
Response: The SPP System Protection and Control Working Group will review all exceptions that are brought to the Planning Coordinator. The supplemental load shed approach was the position developed to represent the best balance between competing		

Organization	Yes or No	Question 2 Comment
entities while ensuring an adequate degree of reliability is achieved.		
American Electric Power	No	AEP is not aware of any potential adverse impacts to reliability or commerce in a neighboring region or interconnection that might occur as a result of the proposed standard.
Response: Thank you for your comment.		
Bonneville Power Administration	No	
Salt River Project	No	
Westar Energy	No	
Southwestern Power Administration	No	
City of Abbeville	No	

3. **Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?**

Summary Consideration:

Organization	Yes or No	Question 3 Comment
City of Abbeville	Yes	Yes, the financial impact of compliance on a small municipally owned system such as Abbeville,s could impact the welfare of our citizens.......
Response: The cost for smaller entities to implement was considered during PRC-006-SPP-01 development. NERC standard PRC-006-1 requires the Planning Coordinator to identify which entities will participate in its UFLS scheme, including the number of steps and percent load an entity will shed. The SPP UFLS SDT recognized that UFLS entities with a load of less than 100 MW may have difficulty in implementing more than one UFLS step and in meeting a tight tolerance. Accordingly, Requirement 2 states that such entities shall not be required to have more than one UFLS step. This should limit additional cost requirements for these smaller entities to comply with the standard, but with minimal consequence to operating system reliability.		
American Electric Power	No	AEP is not aware of any serious or substantial threats to public health, safety, welfare, or national security that might occur as a result of the proposed standard.
Response: Thank you for your comment.		
City Water & Light	No	Not to our knowledge.
Response: Thank you for your comment.		
Bonneville Power Administration	No	
Salt River Project	No	

Organization	Yes or No	Question 3 Comment
Westar Energy	No	
Southwestern Power Administration	No	
Omaha Public Power District	No	
Lincoln Electric System	No	
Southwestern Public Service Company, an Xcel Energy company	No	

4. **Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

Summary Consideration:

Organization	Yes or No	Question 4 Comment
City of Abbeville	Yes	Yes, there has is a serious burden financially the could prevent competitiveness...
Response: The cost for smaller entities to implement was considered during PRC-006-SPP-01 development. NERC standard PRC-006-1 requires the Planning Coordinator to identify which entities will participate in its UFLS scheme, including the number of steps and percent load an entity will shed. The SPP UFLS SDT recognized that UFLS entities with a load of less than 100 MW may have difficulty in implementing more than one UFLS step and in meeting a tight tolerance. Accordingly, Requirement 2 states that such entities shall not be required to have more than one UFLS step. This should limit additional cost requirements for these smaller entities to comply with the standard, but with minimal consequence to operating system reliability.		
City Water & Light	No	Not to our knowledge.
Response: Thank you for your comment.		
American Electric Power	No	AEP is not aware of any serious or substantial burden on competitive markets within the interconnection (that is not necessary for reliability) that might occur as a result of the proposed standard.
Response: Thank you for your comment.		
Bonneville Power Administration	No	
Salt River Project	No	

Organization	Yes or No	Question 4 Comment
Westar Energy	No	
Southwestern Power Administration	No	
Omaha Public Power District	No	
Lincoln Electric System	No	
Southwestern Public Service Company, an Xcel Energy company	No	

5. Does the proposed regional reliability standard meet at least one of the following criteria?

- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Summary Consideration:

Organization	Yes or No	Question 5 Comment
Southwestern Power Administration	Yes	I agree with all three statements
Response: Thank you for your comment.		
American Electric Power	Yes	While AEP would prefer to follow a single continent-wide approach in regard to this standard (and participated in the regional standard development process), we concur that the proposed standard meets at least one of the above criteria.
Response: Thank you for your comment.		
Bonneville Power Administration	Yes	
City Water & Light	Yes	
Westar Energy	Yes	
City of Abbeville	Yes	

Southwestern Public Service Company, an Xcel Energy company	Yes	
Omaha Public Power District	No	SPP's regional standard does not meet the criteria that FERC has indicated as being necessary in order to receive FERC's approval. FERC has indicated that they will consider approving regional differences (variances) and Regional Standards that meet the following criteria:Item 34: Â¶ 274 of the ERO Certification Order:"The Commission has stated that we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System. The FERC-approved definitions of Regional Standard (from the Rules of Procedure) are:"Regional reliability standard" means a type of reliability standards that is applicable only within a particular regional entity or group of regional entities. A regional reliability standard may augment, add detail to, or implement another reliability standard or cover matters not addressed by other reliability standards. Regional reliability standards, upon adoption by NERC and approval by the applicable ERO governmental authority(ies), shall be reliability standards and shall be enforced within the applicable regional entity or regional entities pursuant to delegated authorities.We do not believe that the SPP RE standard meets either of the FERC qualifications nor does it meet the FERC approved definition of a Regional reliability standard, which will likely have bearing on its approval at FERC. In addition to the SPP regional standard's failure to meet either the FERC qualifications or definition, there are also deficiencies within the proposed requirements. For Requirement R2, a UFLS entity with less than 100 MW of forecast peak load is expected to establish at least one UFLS step that sheds at least 30% of its load. However, R2 fails to state the frequency trip point for this step(s) and simply states it will be "assigned by the Planning Coordinator". Although SPP acknowledges within the standard that "some small

		UFLS entities may experience difficulty", the requirement fails to include a transparent decision-making process by which these small entities can express their concerns and understand SPP's process. Considering the NERC continent-wide standard, PRC-006-1 R14, allows for entities to submit comments with the understanding that their PC will respond, we believe such a process is important to include within a regional standard as well. Additionally, embedding the actual Frequency setpoints within the standard will only hinder the SPP RTO's ability to issue frequency setpoint changes as required by their own studies. Having a transparent decision-making process is a concept lacking within the proposed Requirement R8 as well. As written, R8 states that a Generator Owner must provide technical evidence demonstrating that a generating unit cannot be operated in the specified frequency range. If this is the case, the entity must shed supplementary load, if they have it. Despite the validity of the requirement, there is no indication of when such technical evidence must be provided or by what process or criteria the SPP Planning Coordinator will determine whether the entity's technical justification is acceptable and in compliance with R8.

Response: PRC-006-SPP-01 was created to be more stringent than the continent-wide Reliability Standard. Any duplicate requirements were removed from PRC-006-SPP-01.

The Planning Coordinator needs the flexibility to be able to assign small entities to different frequency trip points, depending on the location of the load, total number of small entities under 100 MW, and other factors.

Requirement 14 of the continent-wide standard requires PC's to respond to the comments from the UFLS entities. The SPP UFLS Standard does not include duplicate requirements from the continent-wide standard to remove any confusion over a possible double jeopardy situation.

The frequency setpoints for SPP's UFLS plan have not changed since the UFLS was originally created. None of the previous UFLS studies have indicated a need to alter from that approach. If the SPP system changes in the future and the UFLS study indicates a need to change the frequency setpoints, then SPP will change the Standard.

SPP, as the Planning Coordinator, will adopt the SPP Regional Standard as the SPP UFLS Plan.

The SPP System Protection and Control Working Group will review all exceptions that are brought to the Planning Coordinator.

Lincoln Electric System	No	SPP’s regional standard does not meet the criteria that FERC has indicated as being necessary in order to receive FERC’s approval. FERC has indicated that they will consider approving regional differences (variances) and Regional Standards that meet the following criteria:Item 34: Â¶ 274 of the ERO Certification Order:”The Commission has stated that we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System."The FERC-approved definitions of Regional Standard (from the Rules of Procedure) are:”Regional reliability standard” means a type of reliability standards that is applicable only within a particular regional entity or group of regional entities. A regional reliability standard may augment, add detail to, or implement another reliability standard or cover matters not addressed by other reliability standards. Regional reliability standards, upon adoption by NERC and approval by the applicable ERO governmental authority(ies), shall be reliability standards and shall be enforced within the applicable regional entity or regional entities pursuant to delegated authorities.We do not believe that the SPP RE standard meets either of the FERC qualifications nor does it meet the FERC approved definition of a Regional reliability standard, which will likely have bearing on its approval at FERC. In addition to the SPP regional standard’s failure to meet either the FERC qualifications or definition, there are also deficiencies within the proposed requirements. For Requirement R2, a UFLS entity with less than 100 MW of forecast peak load is expected to establish at least one UFLS step that sheds at least 30% of its load. However, R2 fails to state the frequency trip point for this step(s) and simply states it will be “assigned by the Planning Coordinator”. Although SPP acknowledges within the standard that “some small UFLS entities may experience difficulty”, the requirement fails to include a transparent decision-making process by which these small entities can express their concerns and understand SPP’s process. Considering the NERC continent-wide standard, PRC-006-1 R14, allows for entities to submit comments with the

		understanding that their PC will respond, we believe such a process is important to include within a regional standard as well.Having a transparent decision-making process is a concept lacking within the proposed Requirement R8 as well. As written, R8 states that a Generator Owner must provide technical evidence demonstrating that a generating unit cannot be operated in the specified frequency range. If this is the case, the entity must shed supplementary load, if they have it. Despite the validity of the requirement, there is no indication of when such technical evidence must be provided or by what process or criteria the SPP Planning Coordinator will determine whether the entity's technical justification is acceptable and in compliance with R8.
Response: PRC-006-SPP-01 was created to be more stringent than the continent-wide Reliability Standard. Any duplicate requirements were removed from PRC-006-SPP-01. The Planning Coordinator needs the flexibility to be able to assign small entities to different frequency trip points, depending on the location of the load, total number of small entities under 100 MW, and other factors. Requirement 14 of the continent-wide standard requires PC's to respond to the comments from the UFLS entities. The SPP UFLS Standard does not include duplicate requirements from the continent-wide standard to remove any confusion over a possible double jeopardy situation. The frequency setpoints for SPP's UFLS plan have not changed since the UFLS was originally created. None of the previous UFLS studies have indicated a need to alter from that approach. If the SPP system changes in the future and the UFLS study indicates a need to change the frequency setpoints, then SPP will change the Standard. SPP, as the Planning Coordinator, will adopt the SPP Regional Standard as the SPP UFLS Plan. The SPP System Protection and Control Working Group will review all exceptions that are brought to the Planning Coordinator.		
Salt River Project	No	

END OF REPORT

Exhibit F

SPP RE Record of Development of Proposed Regional Reliability Standard PRC-006-SPP-01

SPP UFLS Regional Standard Voting Ballot--Calculation of Weighted Vote

Voting Segment	Registered Ballot Body	Vote Cast	Vote Yes	Vote No	Weighted Vote Yes	Weighted Vote No
Transmission	18	12	6	6	0.50	0.50
Generation	8	4	3	1	0.75	0.25
Marketer/Broker	0	0	0	0	-	0.00
Distribution/Load Serving Entity	21	14	3	11	0.21	0.79
End User and Public Interest	5	4	4	0	1.00	0.00
Weighted Total	52	34	16	18	2.46	1.54

Weighted Affirmative Vote: 62%

Vote Failed (2/3 or 66.7% Affirmative Vote Required to Pass Standard for Further Consideration)

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Transmission

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding   Number: PRC-006-SPP-01   Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name:	Party	Vote	Comments
1	2011-02-04	Cherie Broadrick	Sunflower Electric Power Corporation	Affirmative	
2	2011-02-08	Ronnie Frizzell	Arkansas Electric Coopertive Corporation	Negative	AECC believes the upper limits proposed for Steps 1 and 2 of R1.1 are too restrictive and should be removed. These limits do not allow adequate flexibility to be included in plans to address real world variations, which will occur once a plan is implemented. These limits will result in SPP members, especially AECC, not being able to meet the requirements of the standard on a performance basis 100% of the time. AECC understands the desire to limit the amount of load shed to prevent over-shedding and does not oppose the 45% upper limit for Step 3. AECC has expressed to the SPCWG, SPP RE staff, and others its concern for the upper limits in Steps 1 and 2 since they were first approved in Criteria 7.3. AECC has proven to the SPCWG that due to the AECC load profile it is not possible for AECC to meet the requirements of Criteria 7.3 100% of the time. AECC believes that if the analysis were performed by other entities it is not the only one that will have difficulty meeting the requirements of R1.1 100% of the time. AECC's dilemma is based on the fact that AECC has included in its plan approximately 300 Mw of arc furnace load. AECC believes that during a UF event this type of load being on line would not be advantageous to maintaining system stability and therefore should be removed as soon as possible. Attempting to do its part to ensure system reliability while using good utility practice and meeting the requirements of Criteria 7.3, AECC has included this load in Steps 1 and 2 of AECC's plan. AECC also believes that dropping 300 MW of load concentrated in a small portion of the network in a single step is unwise. On peak these furnaces make up more than 6% of AECC's total load in a given step. With a 5% window in Step 1 and a 6% load, it is simple to see that the state of the load will determine whether or not the requirements can be met. This carries over to Step 2 with a cumulative 10% window and 12% load. It is obvious that if AECC develops a plan which meets the window requirements without considering the furnace load and the furnace load is on line at the time of an event or compliance review then AECC will exceed the upper limits as proposed. It is equally obvious that if AECC develops a plan including the furnace load and the furnaces are not on line during an event or compliance review then AECC doesn't meet the minimum limits as proposed. This is exacerbated at times other than peaks and is especially problematic during light load periods. As a result, SPP recognized AECC's situation and granted AECC's request for a waiver from Criteria 7.3. Since the proposed regional standard incorporates similar "windows" as Criteria 7.3, it too will impose the same restrictions which will be impossible for AECC and possibly others to meet 100% of the time if passed. AECC believes its only recourse will be to ask for and have SPP grant a continuation of AECC's waiver under the regional standard.

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Transmission

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding Number: PRC-006-SPP-01 Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name:	Party	Vote	Comments
			Arkansas Electric Coopertive Corporation (Continued)		At issue is not the ability to design and implement a UFLS plan capable of meeting the requirements of R1.1 but the ability of that plan once implemented to perform within the limits of R1.1 under changing conditions. Real time conditions unlike planning conditions are not static. Changes in seasons, weather, load availability, and many other factors will affect the actual performance of a plan and the plans ability to meet compliance. For AECC these conditions can change within seconds and without prior knowledge. The SPCWG and drafting team have made it clear that this standard covers the development, implementation, and assessment of a plan. In reality, it is the performance of that plan under real world conditions that is important. AECC believes an important goal of UFLS plans should be to meet the requirements of R1.1 as much of the time as possible. Plan performance at times other than peak conditions is not addressed in the proposed standard. Requirement R4 is vague as to how a Planning Authority will conduct technical assessments and the basis used for these assessments. Add to this the fact that SPP has historically used times other than peaks to measure compliance, the unpredictability of a UF event, and the fact that NERC has made clear its intentions of developing and measuring standards based on performance and a clear picture emerges. Compliance to the standard based on times other than designed peaks is a real possibility. It is therefore imperative that plans be designed with as much flexibility as possible. It was SPPs measuring compliance at times other than the designed peak conditions which led to AECC's need for a waiver of Criteria 7.3. AECC believes the upper limits of Step 1 and 2 are too restrictive and will create a situation where SPP members will be found in violation of the requirements under performance evaluations. AECC has proven this to be true. Again, AECC believes that if the analysis were done it is not the only entity that will have difficulty meeting the "window" requirements 100% of the time. AECC requests the drafting team remove the upper limits for Steps 1 and 2. AECC also requests the drafting team consider including performance metrics in the standard to ensure that plans are affective for reasonable periods of time (load levels).

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Transmission

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding   Number: PRC-006-SPP-01   Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name:	Party	Vote	Comments
3	2011-02-09	Eric Ruskamp	Lincoln Electric System	Negative	LES appreciates the amount of time and effort this SDT has put into this proposed SPP RE UFLS standard, however LES does not believe it will accomplish the intent of the regional standard, which is to create consistent and enforceable UFLS program across the entire SPP Planning Coordinator footprint which spans 3 Regional Entity regions. As a proposed Regional Standard, this standard would only apply to the entities registered within the SPP RE region; it would have no effect on the MRO (or SERC) registered entities. This separation can be confusing as the Nebraska entities operate within the SPP RTO and the MRO RE, however the RTO and the RE perform very distinct functions. For example, while the SPP RTO and the SPP RE share the same name "SPP" the two organizations operate independently, fulfill completely different functions and have distinct footprints. The approval of a Regional Standard in the SPP RE does not affect the SPP RTO membership just as an approval of a SPP RTO criteria within the SPP RTO does not affect the SPP RE membership. LES believes that a UFLS program should cover the entire SPP RTO (or more specifically the Planning Coordinator) footprint, however passing a SPP RE Regional Standard will not accomplish this. In only 2 of the 8 NERC Regional Entity regions do the RE boundaries align with the RTO boundaries, thus it makes little sense to develop UFLS programs on a RE footprint basis as is required in the current mandatory and enforceable NERC UFLS standard. NERC recognized this fact and has assigned the responsibility of developing a UFLS program to the Planning Coordinator, i.e. the SPP RTO, in the new continent-wide NERC standard. This new standard was approved by NERC on October 18, 2010 and is pending filing at FERC. http://www.nerc.com/docs/standards/sar/Project_2007-01_PRC-006_clean_20101018.pdf Additionally, some believe that the approval of this SPP RE regional standard would meet the obligations of the SPP RTO to develop a 'UFLS program' per the newly approved NERC standard; however LES does not believe this to be true. Number one, the newly approved NERC standard says that the Planning Coordinator (SPP RTO) must develop a UFLS program, not the NERC Regional Entity (SPP RE). Secondly, the proposed SPP RE regional standard is not a "program" rather it is a 2nd set of requirements requiring the SPP RTO to create a program and the UFLS entities to follow that developed program. If the SPP RE regional standard is approved, the SPP RTO will still have to develop a regional UFLS program, and that program will have to meet the requirements of both the NERC standard and the SPP RE standard. In closing, LES agrees that the SPP RTO should develop a UFLS program per the requirements in the NERC approved PRC-006-1; however the work on developing a SPP RE Regional Standard in not necessary and should be abandoned. Per the new NERC Standard the "UFLS entities" are required to follow their Planning Coordinator's UFLS program, so no SPP RE standard (which would only be enforceable in 2/3rds of the SPP RTO footprint) needs created. The SPP RTO membership should instead focus our efforts on working with the SPP RTO staff to create a UFLS program that will take into consideration the ideas, thoughts and concerns of all of the SPP RTO members including those registered in the SPP RE, MRO and SERC. LES looks forward to working with the SPP RTO staff in developing the SPP RTO (Planning Coordinator) UFLS program per the requirements found in the newly approved NERC standard.
4	2011-02-14	Michael Gammon	Kansas City Power & Light Company	Affirmative	
5	2011-02-15	Gary Cox	Southwestern Power Administration	Negative	Southwestern does not feel ithe standard properly addresses the agency concerns

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Transmission

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding   Number: PRC-006-SPP-01   Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name:	Party	Vote	Comments
6	2011-02-15	Thad Ness	American Electric Power Service Corp. As Agent For Public Svc. Co. Of Oklahoma & SW Ele Pwr Co.	Negative	AEP recognizes the need to coordinate the underfrequency tripping of generators with automatic underfrequency load shedding programs. Furthermore, we recognize the need to evaluate the impact that the premature tripping of a generating unit may have on the Bulk Electric System during a frequency excursion and the potential need to install additional load shedding to compensate for the loss of such a generator. With respect to Requirement 7 of this draft we find it acceptable to require the Generator Owner, where technically feasible, to set their relays and generator control system settings outside of the underfrequency and overfrequency curves contained within Attachments 1 and 2, respectfully and to require the Generator Owner to supply the data listed in Requirements 6.1 thru 6.5 to the Planning Coordinator, Transmission Owner and/or Distribution Provider. However, we strongly feel that the requirement of the Generator Owner to arrange for load shedding to be installed should be removed from the standard. We also observe that the curves in Attachments 1 and 2 are not consistent with generator off-nominal frequency curves in Attachments to NERC standards PRC-006-1 and draft PRC-024-1 and that this may lead to confusion. We believe that the requirement of the Generator Owner to arrange for load shedding is inconsistent with the resolution between NERC Standard PRC-006-1 "Development and Documentation of Regional UFLS Programs" and draft NERC standard PRC-024-1 "Generator Performance During Frequency and Voltage Excursions." These standards only require that Generator Owners document relay settings or equipment limitations that prevent conformance to the off-nominal frequency curves of those standards and that Planning Coordinators develop and document underfrequency load shedding programs that account for generators whose trip characteristics do not conform to the off-nominal frequency curves of those standards. Neither NERC standard requires the shedding of load by Generation Owners. As written, the SPP standard does not contain any mechanism by which a Generator Owner can require a Transmission Owner or Distribution Provider to install load shedding on the Generator Owner's behalf. A Generator Owner who owns no transmission or distribution, may be forced into non-compliance with the standard if they can not reach an agreement with a Transmission Owner or Distribution Owner to shed load. The requirement (R7) causes one entity's compliance to be dependent on the cooperation of another entity and such dependence has been problematic in certain instances where it has been proposed in other draft standards. It is for the reasons documented above that AEP strongly believes that Requirement 7 and its associated measures and violation severity levels should be revised by removing the requirement for Generator Owners to arrange for load shedding. The following comments are made in regards to R4: 1) There is no definition of "specified island" for this requirement. This could conceivably tie back to R3, but this is not clear. 2) R4 as written would seem to be merely a compliance check that UFLS entities did what they were supposed to do to satisfy R1 or R2. 3) In using the term "assessment" in R4, it is not clear if perhaps the drafting team was intending a study on whether the UFLS program "works." In any case, the NERC PRC-006-1 standard now approved by the NERC Board already has the requirement on the Planning Coordinator for a study type of assessment. For the reasons stated, AEP believes R4 could be removed entirely.
7	2011-02-15	Doug Peterchuck	Omaha Public Power District	Negative	PRC-006-SPP-01 requires that generator tripping not violate the curves in Attachments 1 and 2. These curves are not the same as the curves in Attachments 1 and 2 of NERC PRC-006-1. How does SPP justify these curves. We recommend attachments 1 and 2 be consistent with the NERC PRC-006 standard. OPPD does not agree with R7.1 that requires generators that do no meet curves in Attachments 1 and 2 to shed equal or greater than the maximum generation. We believe existing generators should be exempt because many won't be able to meet the curves and how can you guarantee that unit is on-line during the event?
8	2011-02-15	Louis C. Guidry, PE	Cleco Corporation	Affirmative	

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Transmission

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding Number: PRC-006-SPP-01 Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name:	Party	Vote	Comments
9	2011-02-16	Rick Koch	Nebraska Public Power District	Negative	NPPD does not support required load shedding when a generator cannot meet the frequency curves of Attachments 1 or 2 without first having a system-specific study performed that confirms the need to shed load in the area of the generator. It is also not clear if an entity that is not registered in the SPP Regional Entity would be required to comply with this SPP RE Standard.
10	2011-02-17	John Pasierb	East Texas Electric Cooperative, Inc.	Affirmative	
11	2011-02-17	Forrest Brock	Western Farmers Electric Cooperative	Affirmative	I am voting affirmative based upon the general content and intent of the standard, but would like to point out some important and necessary clarifications, specifically the following: R4: First bullet needs clarification – Was the intent to mean the PC would perform a new technical assessment within one year after design changes were made to the parameters of the UFLS program or SPP UFLS Standard? Or was the intent that the new assessment would be performed after changes are made to the parameters of the NERC UFLS or SPP UFLS standards? It seems to be clear it is necessary to insert the word “program” before the first use of UFLS and make the word” standards” singular, or insert the acronym “NERC” before the first UFLS to clarify whichever meaning the SDT intends. VSLs for R4: It appears the intent of the SDT is to apply varying VSLs to a situation where the PC does not perform the technical assessment within the required time frame(s). The way these are worded in this version of the standard, the PC will ALWAYS be in trouble at ALL levels of the VSL chart, because the performance of a technical assessment within only ONE day of a situation listed in R4 would satisfy the terms of all the VSL, as it would have been performed WITHIN all of the time frames specified in the VSLs. Recommended wording would be, “The Planning Coordinator performed a technical assessment after five years, but less than five years and three months, or after one year, but less than one year and three months following the occurrence of one of the situations listed in R4.” – and so forth for the ascending levels of the VSLs.
12	2011-02-17	Allen Klassen	Westar Energy, Inc.	Affirmative	
13	N/A	Michael Moltane	ITC Great Plains, LLC	N/A	
14	N/A	John Allen	City Utilities Of Springfield, MO	N/A	
15	N/A	Jake Langthorn	Oklahoma Gas And Electric Co.	N/A	
16	N/A	William Grant	Southwestern Public Service Co. (Xcel Energy)	N/A	
17	N/A	William Dowling	Midwest Energy, Inc.	N/A	
18	N/A	Rick Bartlett	Independence Power & Light (Independence,Missouri)	N/A	

Segment Result

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Transmission

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding   Number: PRC-006-SPP-01   Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name:	Party	Vote	Comments
	Ballot Body	18			
	Votes Casted	12			
	Affirmative	6			
	Negative	6			

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Generation

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding Number: PRC-006-SPP-01 Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Name:	Submit Date	Name:	Party	Vote	Comment
1	2011-02-12	Greg Froehling	Green Country Energy, LLC	Affirmative	
2	2011-02-15	Chris Lang	Yoakum Electric Generating Cooperat	Affirmative	
3	2011-02-16	Rick Jackson	AES Shady Point, LLC	Affirmative	Regarding R7 - If unable to meet the under/over frequency curves, the generator owner shall arrange for load shedding ... The Generator Owner would not have any load to shed or control to shed load.
4	2011-02-17	James W Thompson	Edison Mission Marketing & Trading, Inc.	Negative	
5	N/A	Mona Johnson	Borger Energy Associates, LP	N/A	
6	N/A	Matthew Courter	NAES Corporation - Blackhawk	N/A	
7	N/A	Krista Mathews	Calpine Corporation	N/A	
8	N/A	Greg Froehling	Green Country Operating Services	N/A	

Segment Result

	Ballot Body	8
	Votes Casted	4
	Affirmative	3
	Negative	1

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Distribution/Load Serving Entity

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding Number: PRC-006-SPP-01 Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name:	Party	Vote	Comments
1	2011-02-03	Terri Pyle	Oklahoma Municipal Power Authority	Affirmative	
2	2011-02-03	Neal Williams	Poplar Bluff	Negative	
3	2011-02-04	Jake Rice III	City Water & Light - Jonesboro, Arkansas	Affirmative	
4	2011-02-08	Mike Garbow	Petit Jean Electric Cooperative	Negative	Petit Jean Electric agrees with AECC's comments and asks that the drafting team remove the upper limits on Steps 1 and 2 in R1.1 and consider adding performance metrics to the standard.
5	2011-02-08	Scott Rorex	Clay County Electric Cooperative, Corp.	Negative	Clay County Electric Cooperative, Corp. agrees with Arkansas Electric Cooperative Corp. comments and asks that the drafting team remove the upper limits on Steps 1 and 2 in R1.1 and consider adding performance metrics to the standard.
6	2011-02-08	C Wayne Whitaker	Southwest Arkansas Electric Cooperative	Negative	Southwest Arkansas Electric Cooperative agrees with AECC's comments and asks that the drafting team remove the upper limits on steps 1 and 2 in R1.1 . Also, consider adding performance metrics to the standard.
7	2011-02-08	Jon Joyce	First Electric Cooperative	Negative	First Electric Cooperative agrees with AECC's comments and asks that the drafting team remove the upper limits on Steps 1 and 2 in R1.1 and consider adding performance metrics to the standard.
8	2011-02-08	Brad Harrison	Mississippi County Electric Cooperative	Negative	MCEC agrees with AECC's comments and asks that the drafting team remove the upper limits on Steps 1 and 2 in R1.1 and consider adding performance metrics to the standard
9	2011-02-09	Keith Blocker	Craighead Electric Cooperative	Negative	Craighead Electric agrees with AECC's comments and asks that the drafting team remove the upper limits on Steps 1 and 2 in R1.1 and consider adding performance metrics to the standard.
10	2011-02-10	Rodney L. Chapman	Ashley-Chicot	Negative	Ashley-Chicot agrees with AECC's comments and asks that the drafting team remove the upper limits on STEPS 1 and 2 in R1.1 and consider adding performance metrics to the standard.
11	2011-02-10	David Brock	Carroll Electric Cooperative	Negative	Carroll Electric agrees with AECC's comments and asks that the drafting team remove the upper limits on Steps 1 and 2 in R1.1 and consider adding performance metrics to the standard.

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Distribution/Load Serving Entity

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding   Number: PRC-006-SPP-01   Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name:	Party	Vote	Comments
12	2011-02-14	Robby Stinnett	Ouachita Electric Cooperative	Negative	Ouachita Electric Cooperative agrees with AECC's comments and asks that the drafting team remove the upper limits on Steps 1 and 2 in R1.1 and consider adding performance metrics to the standard.
13	2011-02-15	Shane McMinn	Golden Spread Electric Cooperative, Inc.	Affirmative	
14	2011-02-16	Mark W. Wurm	Board Of Public Utilities, City Of McPherson, Kansas	Negative	For future concerns (not for present concerns) BPU believes the regional standard should have a mechanism such as the present SPP program wherein an entity may request a waiver if special circumstances arise. We can anticipate situations wherein tradeoffs will exist between safety, reliability, and a particular entities types of load (for instance we see a safety issue with purposefully tripping certain industries such as a refinery).
15	N/A	Errol Ortego	Louisiana Energy & Power Authority	N/A	N/A
16	N/A	Alan Wagoner	Arkansas Valley Electric Coop	N/A	N/A
17	N/A	Eddy Reece	Rayburn Country Electric Cooperative, Inc.	N/A	N/A
18	N/A	Michael Swearingen	Tri-County Electric Cooperative Oklahoma	N/A	N/A
19	N/A	Jason Strong	North Arkansas Electric Coop	N/A	N/A
20	N/A	Jimmy Cook	Woodruff Electric Cooperative Corporation	N/A	N/A
21	N/A	Chris Saunier	City Of Abbeville	N/A	N/A

Segment Result

	Ballot Body	21
	Votes Casted	14
	Affirmative	3
	Negative	11

SPP UFLS Regional Standard Voting Ballot- Voting Segment- End User and Public Interest

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding Number: PRC-006-SPP-01 Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name:	Organization	Vote	Comments
1	2011-02-03	Jason Speer	Jason Speer	Affirmative	
2	2011-02-03	Mathew J. Thykkuttathil	Mathew J Thykkuttathil	Affirmative	
3	2011-02-03	David Kelley	David Kelley	Affirmative	
4	2011-02-04	Heidt Melson	Heidt Melson	Affirmative	
5	N/A	Tim Craig	Tim Craig	N/A	

Segment Result

	Ballot Body	5
	Votes Casted	4
	Affirmative	4
	Negative	0

SPP UFLS Regional Standard Voting Ballot--Calculation of Weighted Vote

Voting Segment	Registered Ballot Body	Vote Cast	Vote Yes	Vote No	Weighted Vote Yes	Weighted Vote No
Transmission	19	15	8	7	0.53	0.47
Generation	10	7	5	2	0.71	0.29
Marketer/Broker	1	1	1	0	1.00	0.00
Distribution/Load Serving Entity	23	17	9	8	0.53	0.47
End User and Public Interest	6	4	4	0	1.00	0.00
Weighted Total	59	44	27	17	3.78	1.22

Weighted Affirmative Vote: 76%

Vote Passed (2/3 or 66.7% Affirmative Vote Required to Pass Standard for Further Consideration)

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Transmission

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding   Number: PRC-006-SPP-01   Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name	Party		Comments
1	2011-10-15	Doug Peterchuck	Omaha Public Power District	Negative	In general, a regional standard is not necessary to support the actual NERC PRC-006-1 Standard. Per the PRC-006-1 Standard, the PC should create the actual UFLS plan. For example, the MRO RE is not creating a regional standard. Also, this regional plan directly circumvents many of the acual requirements of the PRC-006-1 Standard.
2	2011-10-17	Louis C. Guidry	Cleco Corporation	Affirmative	
3	2011-10-17	Don Schmit	Nebraska Public Power District	Negative	NPPD has not completed evaluation of this Standard on it's Nuclear Plant and in that light cannot vote affirmative at this time.
4	2011-10-17	Jake Langthorn	Oklahoma Gas And Electric Co.	Affirmative	
5	2011-10-18	Ronnie Frizzell	Arkansas Electric Coopertive Corporation	Negative	Draft 7 does not address AECC's concerns which have been expressed in prior comments.
6	2011-10-19	John Allen	City Utilities Of Springfield, MO	Affirmative	
7	2011-10-21	John Pasierb	East Texas Electric Cooperative, Inc.	Affirmative	
8	2011-10-24	Michael Wech	Southwestern Power Administration	Negative	Southwestern feels that giving the Planning Coordinator (PC) the authority to establish what entities require UFLS equipment without any clearly defined methodology or requirements (on the P.C.) is of great concern to the Agency. This standard (as written) in today's bulk power system will not be not applicable to Southwestern. However, by authorizing the Planning Coordinator to decide based on (?? criteria) what and where new UFLS relays shall be installed and that could then make Southwestern responsible for this standard is enough cause for concern for the Agency to vote against the standard as written.

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Transmission

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding   Number: PRC-006-SPP-01   Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name	Party		Comments
9	2011-10-25	Eric Ruskamp	Lincoln Electric System	Negative	LES recognizes the amount of effort the SPP RE, SPP RTO and the SPP membership has put into the development of this Regional standard, however LES must vote negative on this standard based for the following reasons. (paragraph break) This Regional standard is not needed with the NERC BOT adoption of NERC standard PRC-006-1 on October 18, 2010. LES believes that a UFLS program should cover the entire SPP RTO (or more specifically the Planning Coordinator) footprint, however passing a SPP RE Regional Standard will not accomplish this. In only 2 of the 8 NERC RE Regions do the RE boundaries align with the RTO boundaries, thus it makes little sense to develop UFLS programs on a RE footprint basis as is required in the current mandatory and enforceable NERC UFLS standard, PRC-006-0 (version zero). NERC recognized this fact and has assigned the responsibility of developing a UFLS program to the Planning Coordinator, i.e. the SPP RTO, in the new continent-wide NERC standard PRC-006-1. FERC also agrees with this approach as is evident in their NOPR to approve PRC-006-1 filed on October 20, 2011 (Docket No. RM11-20-000). Within Paragraph 46 of this Order FERC states: (paragraph break) Requirement R2.3 allows planning coordinators to “adjust the island boundaries to differ from the Regional Entity area boundaries by mutual consent where necessary” to preserve contiguous island boundaries that better reflect simulations. The Commission agrees that identifying island boundaries based on where they are likely to occur due to system characteristics, as opposed to maintaining rigid Regional Entity area boundaries, should result in more effective UFLS programs. Accordingly, the Commission encourages cooperation among entities to create UFLS programs that set island boundaries based on where separations are expected to occur during an underfrequency event. (paragraph break) As the SPP RE Standard Drafting Team knows, the PRC-006-1 NERC standard essentially requires that the Planning Coordinators (the SPP RTO) develop a UFLS Program for their Planning Coordinator footprint, and that their UFLS Entities (which WOULD include the non SPP RE registered entities) are required to follow that Program. This SPP RE regional standard (which was written for the most part by SPP RTO staff) would be duplicative, confusing and unnecessary based on the fore mentioned facts. Rather than creating another standard to comply with, the SPP RTO and their members (including LES) should work toward creating the SPP RTO’s UFLS program, that will incorporate the ideas outlined in the draft SPP RE standards AND meet the requirements written within the NERC standard. This SPP RE Standard does not meet the SPP RTO’s NERC obligations to create a UFLS program. (paragraph break) It is important for the SPP RE Board to recognize that this proposed SPP RE standard will not apply to the “UFLS entities” outside of the SPP RE footprint, currently in the MRO and SERC regions, but could continue to change as the SPP RTO looks to expand its footprint…. and the SPP RE footprint will remain unchanged. These “UFLS Entities” outside of the SPP RE are not registered in the SPP RE region and are therefore outside of the SPP RE’s ‘jurisdiction’. It appears that the draft SPP RE UFLS standards is attempting to pull in these non SPP RE UFLS Entities, however this will not be successful unless a change is made to the NERC Compliance Registry. In contrast, per the NERC standard PRC-006-1, non SPP RE entities would be required to follow the SPP RTO UFLS program, because the regional limitation is removed from the standard. (paragraph break) LES looks forward to working with SPP RTO staff in creating the SPP RTO’s (i.e. the Planning Coordinator’s) NERC required UFLS Program which will be mandatory and enforceable in the entire SPP RTO footprint.
10	2011-10-26	Mike Stafford	Grand River Dam Authority	Affirmative	
11	2011-10-27	Robert Rhodes	Southwest Power Pool	Affirmative	
12	2011-10-27	Bo Jones	Westar Energy, Inc.	Affirmative	

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Transmission

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding   Number: PRC-006-SPP-01   Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name	Party		Comments
13	2011-10-28	Thad Ness	American Electric Power Service Corp. As Agent For Public Svc. Co. Of Oklahoma & SW Ele Pwr Co.	Negative	AEP is casting a negative ballot primarily due to the contents of Attachments 1 & 2. These attachments should use the curves as provided in the NERC Standards as the performance criteria in the Regional Standard. Having two sets of curves in the NERC and SPP standards will only cause undue confusion to the industry, without any significant benefit to reliability. While it is true that the generator curves in NERC PRC-006-1 are limited to indicating when generator under- and over-frequency trip settings should be represented in UFLS assessments, these curves are coordinated with NERC draft PRC-024-1 (the generator curves in NERC PRC-006-1 Attachment 1 are the same as PRC-024-1 Attachment 1). NERC PRC-024-1 will require that Generator Owners supply technical justification for any settings within the envelope (no trip zone) of the two curves, same as PRC-006-SPP-1 R7 will require for any settings between its curves. A uniform continent-wide requirement on generator under- and over-frequency tripping really is desirable to avoid confusion. It is also necessary for coordination of generator tripping with continent-wide UFLS performance criteria in the now NERC Board approved NERC PRC-006-1. Nothing is lost if SPP's curves are made the same as draft NERC PRC-024-1. The same non-conforming generator trip settings (perhaps more because NERC Attachment is more restrictive) will still be available to the Planning Coordinator and the PC can still do what it needs to do under SPP R8, including identifying supplementary load shedding, should it find that the UFLS program is degraded. Once NERC PRC-024-1 becomes enforceable, SPP R7, R7.1, and R8 (keep R8.1) can be removed with no change in what a Generator Owner needs to comply with. For R9, we suggest changing the wording so that it is clear that the actionable element of the requirement is that procedures are implemented, rather than requiring that load shedding is to occur. AEP suggests the following suggestion. "The Generator Owner or other UFLS entity(s) shall provide automatic supplementary load shedding capability as required by the Planning Coordinator in accordance with R8.1.1." AEP requests that future drafts use redlining to clearly indicate the changes that have been made since the previous draft. {This comment field does not allow for cut and paste of multiple paragraphs. Please consider modifications to the webpage to allow more functionality.}
14	2011-10-28	Noman Williams	Sunflower Electric Power Corporation	Affirmative	
15	2011-10-30	William Dowling	Midwest Energy, Inc.	Negative	1.□Requirement R7 related to generators meeting the performance curve data is poorly defined. It would seem that “size matters”. Is the applicability to a 700MW unit the same as a 7MW or 0.7MW unit? 2.□Requirement R3 makes it clear that the UFLS entity can elect, at is option, to implement an islanding scheme if it desires. However, in the violation severity level table it is indicated that failure to develop an islanding scheme is a severe violation. 3.□The standard is unclear throughout when data must be provided to the Planning Coordinator. In some cases it says data will be provided upon request. In other instances, such as the violation severity table, it suggests that data must be provided at some interval following a compliance audit. Which is it? If there is a recurring obligation to provide data, what is that frequency of data reporting?

Segment Result

Ballot Body	19
Votes Cast	15
Affirmative	8
Negative	7

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Generation

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding Number: PRC-006-SPP-01 Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name	Party	Vote	Comments
1	2011-10-19	Greg Froehling	Green Country Operating Services, LLC	Affirmative	
2	2011-10-26	Chris Lang	Yoakum Electric Generating Cooperative, Inc.	Affirmative	
3	2011-10-26	Kevin Chaffin	Golden Spread Panhandle Wind Ranch, LLC	Affirmative	
4	2011-10-26	Jeff Pippin	Denver City Energy Associates (Mustang Station)	Affirmative	
5	2011-10-27	Steven Parkey	Tenaska Gateway Partners Ltd	Negative	please clarify what is wanted by a Generator in R7; my relay settings were given in R6
6	2011-10-28	Lindsay Shepard	Mid-Kansas Electric Company, LLC	Affirmative	
7	2011-10-28	James W. Thompson	Edison Mission Marketing & Trading, Inc.	Negative	The term verify is too vague. I would purpose that the term be verify by review of current relay settings.

Segment Result

Ballot Body	10
Votes Cast	7
Affirmative	5
Negative	2

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Marketer/Broker

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding Number: PRC-006-SPP-01 Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name:	Name	Vote	Comments
1	2011-10-27	Bryan Kauffman	Southwestern Public Service Co. (Xcel Energy)	Affirmative	

Segment Result

	Ballot Body	1
	Votes Cast	1
	Affirmative	1
	Negative	0

SPP UFLS Regional Standard Voting Ballot- Voting Segment- Distribution/Load Serving Entity

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding Number: PRC-006-SPP-01 Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name	Party	Vote	Comment
1	2011-10-17	Steve McGie	Coffeyville Municipal Light & Power	Affirmative	
2	2011-10-17	Fred Meyer	The Empire District Electric Company	Affirmative	
3	2011-10-18	Kevin Emery	Carthage Water & Electric Plant	Affirmative	
4	2011-10-18	Wayne Whitaker	Southwest Arkansas Electric Cooperative	Negative	Draft 7 does not address AECC's concerns which have been expressed in prior comments".
5	2011-10-20	John Payne	Kansas Electric Power Cooperative, Inc.	Affirmative	
6	2011-10-21	Michael Garbow	Petit Jean Electric Cooperative	Negative	Draft 7 does not address AECC's concerns which have been expressed in prior comments.
7	2011-10-21	John Pasierb	Northeast Texas Electric Cooperative, Inc	Affirmative	
8	2011-10-25	Wayne Shelton	City Of Malden - Board Of Public Works	Negative	
9	2011-10-26	Neal Williams	Poplar Bluff	Negative	1) R1.1 and R2.2 can be misinterpreted as specifying the amount of load to be shed both on peak and off peak. 2) M1 and M2 do not follow the Reliability Standards Development Procedure by adequately identifying to whom the measure applies. 3) The combination of Requirements with Measures does not follow the Template Guide for New Standards.
10	2011-10-26	Shane McMinn	Golden Spread Electric Cooperative, Inc.	Affirmative	
11	2011-10-27	Ashley Stringer	Oklahoma Municipal Power Authority	Affirmative	
12	2011-10-28	Jake Rice	City Water & Light - Jonesboro, Arkansas	Affirmative	
13	2011-10-28	David Brock	Carroll Electric Cooperative	Negative	
14	2011-10-28	Brett Holland	KCPL - Greater Missouri Operations	Negative	Comments submitted under separate email.
15	2011-10-28	Brian Haley	Piggott Light & Water	Negative	
16	2011-10-28	Michael T Swearingen	Tri-County Electric Cooperative	Affirmative	
17	2011-10-29	Chris Parr	Kansas City Power & Light Company	Negative	See separate email from Mike Gammon for comments

Segment Result

	Ballot Body	23
	Votes Cast	17
	Affirmative	9
	Negative	8

SPP UFLS Regional Standard Voting Ballot- Voting Segment- End User and Public Interest

Title: Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding Number: PRC-006-SPP-01 Purpose: To develop, coordinate and document requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events

Number	Submit Date	Name	Party	Vote	Comments
1	2011-10-16	Pablo Ruiz	Pablo Ruiz- Charles River Associates	Affirmative	
2	2011-10-17	Dan Hartman	Dan Hartman- NW Kansas Regional Energy Collaborative	Affirmative	
3	2011-10-17	Heidt Melson	Heidt Melson	Affirmative	
4	2011-10-28	Rick Bartlett	Rick Bartlett- Independence Power & Light (Independence,Missouri)	Affirmative	

Segment Result

Ballot Body	6
Votes Cast	4
Affirmative	4
Negative	0

Checklist for Quality Review, NERC Board & Governmental Authorities Submittal

Regional Reliability Standard Name: SPP Automatic Underfrequency Load Shedding			
Regional Reliability Standard No: PRC-006-SPP-01			
	QR	**BOT**	**Gov't Auth.***
SAR – *Standard Authorization Request*	X	X	X
File Name: Regional Standards Request SPP UFLS.pdf			
Regional Reliability Standard(s) *(clean - has either been or anticipated to be approved by BOD).*	X	X	X
File Name: PRC-006-SPP-1 (draft 7) Approved by RE Trustees 7-30-12.pdf			
Regional Reliability Standard(s) *(redlined - if revision to existing standard)*	X	X	X
File Name: N/A- This is a new standard			
Implementation Plan *(redlined if different from previous posting).*	X	X	X
File Name: Implementation_Plan_PRC-006-SPP-01.pdf			
Technical Justification	X	X	X
File Name: Technical Evaluation & Assessment PRC-006-SPP-01.pdf			
VRF & VSL Justification	X	X	X
File Name: VRF and VSL Justification_PRC-006-SPP-01.docx			
Mapping Document – *Optional*	X	X	X
File Name: N/A- A Mapping Document does not exist			
Issues Table – *Optional*	X	X	X
File Name: PRC-006-SPP-01- Minority Report.pdf			
Regional Reliability Standard Submittal Request		X	X
File Name: Regional Std Submittal Request PRC-006-SPP-01.doc			
Project Roadmap		X	X
File Name: Roadmap PRC-006-SPP-01.docx			
Order 672 Criteria		X	X
File Name: FERC Order 672 and PRC-006-SPP-01.docx			

Drafting Team Roster with Biographies		x	x
File Name: SDT Bios PRC-006-SPP-01.doc			
Ballot Pool Members		x	x
File Name: Ballot Pool Members & Final Results.pdf			
Final Ballot Results		x	x
File Name: Ballot Pool Members & Final Results.pdf			
Comments & Responses		x	x
File Name: Comments and Responses.pdf			
Petition Filing *(Federal Energy Regulatory Commission)*			x
File Name: N/A- SPP RE has not prepared the FERC Petition Filing			
*Applicable governmental authorities in the United States, Canada, and Mexico			
LINK			
Please provide documents in MS Word format.			

1. Do you agree with the applicable entities of the proposed standard? If not, please explain.

Responses
Yes - 10
No - 9

Organization	Question 1:	Question 1 Comments:
AECC	No	See comments 11 through 15 attached
AEP	Yes	Please specify which entity is responsible for a compliance activity or data submission. For example, R3 includes five entities and nine types of UFLS data. No one entity could provide all of this data, so it would be much clearer and successful to identify which entity provides which types of UFLS data.
Commonwealth Edison Co.	No	Thank you for the opportunity to comment. We spent some time discussing this issue when developing the current draft of the RFC UFLS standard. The Load Serving Entity may not own any equipment, may contract to serve load in blocks that don't necessarily correspond to discrete feeders (i.e. UFLS relay), may have difficulty in providing load information coincident with system load for a specific period of time, and may not even contract to serve load far enough in advance to accurately plan into the future. I suggest that 'LSE' be eliminated as an applicable entity. The TO function may not apply unless the TO serves end-use load. I suggest that rather than making all TOs applicable entities, it should be 'Transmission owners with end-use load'. It would be beneficial to have each of the requirements applicable to a certain entity rather than listing the possibilities for applicability.
Consumers Energy	Yes	
City, Water & Light	Yes	
Farmers' Electric Coop	No	By applying the Standard to a LSE and or DP, SPP is exerting operational control over a distribution utility. In New Mexico, the New Mexico Public Regulation Commission is the regulatory body with oversight, including service standards. This Standard will impose additional costs in equipment and personnel to implement and operate.
SDT Response	**The proposed SPP standard is designed to ensure that during a load shedding event the transmission system should remain intact as long as possible with load shedding occurring as close to the end user as practical. Therefore the proposed SPP standard requires that each DP be responsible for shedding its own native load.**	
Golden Spread	Yes	Golden Spread (GS) agrees with the proposed applicable entities, subject to clarification. Regarding the applicability of the proposed standard to Distribution Providers, GS believes that the entities subject to the requirements of the proposed standard should be limited to entities required to register with SPP Regional Entity as Distribution Providers, i.e., those that meet the criteria of NERC Statement of Compliance Registry Criteria III.b.1, "Distribution provider system serving >25 MW

		of peak load that is directly connected to the bulk power system." GS believes that entities that serve peak load of 25 MW or less, or that are not directly connected to the bulk power system, should not be required to implement automatic UFLS programs, or to participate with other entities to collectively implement by mutual agreement a single automatic UFLS program, absent a demonstration by SPP that expansion of the applicability of this standard to such entities is necessary to assure the reliability of the bulk power system. GS requests that SPP clarify whether GS is correct that the term "Distribution Provider" is meant to be defined consistent with Golden Spread's understanding as stated above.
KCPL	Yes	
KEPCO	Yes	
Lafayette Utilities System	No	As currently drafted, the proposed standard applies to "Load-Serving Entities with a peak integrated hourly load greater than 25 MW" and "Generator Owners of generators with an individual nameplate rating or plants, including Wind Generating Stations, with an aggregate nameplate rating of 10 MVA or greater." (See §§ A.4.3, A.4.4.) Neither of these applicability criteria are consistent with the NERC Statement of Compliance Registry Criteria's registration requirements for Load-Serving Entities ("LSEs") or Generator Owners ("GOs"). Specifically, the Registration Criteria limit registration for LSEs to those entities having peak loads of greater than 25 MW and a direct connection to the Bulk Electric System or designated as the responsible entity for facilities that are part of required Under-Frequency Load Shedding ("UFLS") or Under-Voltage Load Shedding programs. As to GOs, the Registry Criteria require registration only for GOs with individual generation units rated at greater than 20 MVA and direct connections to the Bulk Electric System, facilities rated at greater than 75 MVA, blackstart units, or units that are otherwise demonstrably material to the reliability of the Bulk Electric System. SPP's proposed Automatic UFLS Program is overly broad to the extent that it purports to apply to users, owners, or operators of the Bulk Electric System that are not otherwise required to register and adhere to Commission-approved Reliability Standards. In the absence of a specific demonstration by SPP (such as through engineering studies and analyses) that the LSEs and GOs that SPP proposes shall be subject to its Automatic UFLS Program are material to the reliability of the Bulk Electric System, the Automatic UFLS Program should apply only to those LSEs and GOs independently meeting NERC's Commission-approved Registry Criteria.
Lubbock Power & Light	No	Lubbock Power and Light competes for customers alley by alley with SPS. There are wires on both sides of the alley. It only takes 3 days for a customer to change service providers. Lubbock Power and Light has over 75% of the electric meters. Since the SPS region is so large it would be possible for SPS to perform their load shedding requirements without shedding in Lubbock, while we (Lubbock Power and Light) would be required to shed load on a percentage of the peak. This would give SPS a unfair business advantage.
National Rural Electric Cooperative Association (NRECA)	No	The Statement of Compliance Registry Criteria (5.0) states that "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." The Applicability portion of this draft standard puts the burden of demonstration of materiality for a Distribution (4.2.1) or Generation Entity (4.4.1) that may not be presently included on the Compliance Registry on the Planning Coordinators or Transmission Planner. In addition, this standard lowers the criteria for registration for Generation Owners from the threshold of > 20 MVA (gross nameplate rating)

		to an aggregate nameplate rating of 10 MVA or greater with no documentation to support the deviation from the Statement of Compliance Registry Criteria (5.0).
Nebraska Public Power District	Yes	
Occidental	No	With regard to the applicability to Generator Owners, the minimum nameplate rating of 10 MVA should be at the least increased to 20 MVA to match the existing registration requirements of NERC. Lowering the threshold to 10MVA is problematic for those generation owners who are not required to register with NERC as a Generator Owner to comply. At this time, NERC has determined that these smaller generators are not significant enough to be "crucial to the reliability of the Bulk Electric System".
OMPA	No	OMPA would like to express its serious concerns over the applicability being proposed in this standard as it pertains to generators. The standard proposes, under Section 4.4, that the requirements apply to “generators with an individual nameplate rating or plants, including Wind Generating Stations, with an aggregate nameplate rating of 10 MVA or greater.” OMPA objects to this applicability criteria for the following reasons. 1. NERC’s Statement of Compliance Registry Criteria limits generators 20 MVA or greater (individual unit) or 75 MVA or greater (aggregate nameplate rating) AND directly connected to the bulk power system. We feel that this Criteria is satisfactory, and that the Working Group has not presented their justification for reducing the applicability requirement to 10 MVA or greater (aggregate nameplate rating). 2. OMPA also feels that the proposed 10 MVA level will have the unintended consequence of pulling many small generators into the UFLS system, which have little, if any, impact on improving reliability. As an example, many municipal systems in Kansas have an aggregate nameplate capacity in excess of 10 MVA and will be subject to this standard; however, these units are typically reserve units that are infrequently in service. 3. It appears that the 10 MVA limit is intended to address the impact of Wind Farms, which is comprised of many small generating units. OMPA feels that wind generators should be addressed separately, and that a proposed 10 MVA aggregate threshold for all generating units is not the appropriate method to accomplish this goal. 4. If this standard were to apply to the many small generators typically owned by municipal systems, it could have the unintended consequence of creating a competitive disadvantage without a corresponding impact on reliability. It would be cost prohibitive for many of these owners to install the necessary protective relaying on these units.
SPRM	No	We agree with list of applicable entities. We agree with the idea of accounting for all load and generation in the footprint.

		However, we are concerned that the current draft standard exceeds the NERC Statement of Compliance Registry Criteria. It is our opinion that this should be accomplished through the NERC registry process so that it is consistent across all regions.
SPS	Yes	It is unclear how the standard could be enforced against generation entities who are not required to register by NERC.
SWPA (Gary Cox)	Yes	
SWPA (Mike Wech)	Yes	
SDT Response	**In the revised standard, the SDT has removed LSE's and Transmission Planners from the applicability section. We have also removed the more stringent requirements on the Distribution Providers and Generations Owners. Only applicable entities per the NERC registry will be required to register. However, SPP will conduct a technical study in 2010 to verify the effectiveness of the design based on the participation of these entities. If it is determined that the program is ineffective due to non-registered entities having a significant impact on the SPP UFLS program the Regional Entity may require unregistered Distribution Providers or Generation Owners to register.**	

2. Are there entities, not currently on the registered entities list, that need to comply to ensure effectiveness?

Responses
Yes - 4
No - 13

Organization	Question 2:	Question 2 Comments:
AECC		The registration of entities is a separate issue and should not be considered as part of standard development.
AEP	No	
Commonwealth Edison Co.	No	
Consumers Energy	Yes	While it is certainly true for automatic UFLS that every MVA matters, it might be less important if a 10 MVA generator is connected at less than 69 KV. I believe that it is correct to go below NERC registry criteria for automatic UFLS, but it might be more acceptable to Generators if the phrase "which is connected to the BES at 100 KV or greater" was added to the end of a sentence.
City, Water & Light	No	
Farmers' Electric Coop	No	I am aware of one entity in our area that is currently exempt from NERC Standards due to size and/or voltage limitations. Under the SPP proposal, this entity could be required to register and comply. I do not believe this would increase the reliability of the Bulk Electric System.
Golden Spread	Yes	Golden Spread (GS) does not have the needed information to answer this. However, GS members participated at a higher percentage level than required by the SPP Criteria during the June 17, 2008 UFLS event in the Southwestern Public Service (SPS) control area. Entities that currently do not participate under the SPP Criteria cause the rest to participate at a higher level. It is only fair that all entities serving end use load that meet the thresholds set forth in the NERC Statement of Compliance Registry Criteria should participate in UFLS.
KCPL	No	
KEPCO	No	The registry list contains the significant players needed for effective UFLS programs.
Lubbock Power & Light	No	
National Rural Electric Cooperative Association (NRECA)	No	Since there is no technical support included with the posting to justify the deviation from Statement of Compliance Registry Criteria (5.0) it is difficult to determine the effectiveness of the additions to the Compliance Registry. As discussed in question #1, for deviations from the criteria the Regional Entity is responsible for demonstrating the materiality of an entity.
Nebraska Public Power District	No	
Occidental	No	

OMPA	Yes	This will undoubtedly require some smaller entities that are not current registered to comply with these new standard requirements. These smaller entities may have generators that are > 10 MVA and therefore be required to meet this standard although they have little, if any, impact on the bulk power system. As an example, many municipal systems in Kansas have an aggregate nameplate capacity in excess of 10 MVA and will be subject to the standard; however, these units are typically reserve units that are infrequently in service.
SPRM	Yes	This is related to the answer to question 1. What is the NERC process for requiring small non-registered entities to have a UFLS program and therefore be required to register as a DP/LSE? It is our opinion that this should be accomplished through the NERC registry process so that it is consistent across all regions.
SPS	No	
SWPA (Gary Cox)	No	
SWPA (Mike Wech)	No	
SDT Response	**In the revised Standard, only applicable entities per the NERC registry will be included. SPP will conduct a technical study in 2010 to verify the effectiveness of the design based on participation of these registered entities. If it is determined that the program is ineffective due to non-registered entities having a significant impact on the SPP UFLS program and not participating, the entity will be included by going through the NERC registry process. The RC will determine the impact of non-registered entities.**	

3. **This standard proposes changing to a planning based standard from an operational based standard as described in current SPP Criteria 7.3. Do you agree with this approach? If not, please suggest why not?**

Responses
Yes - 13
No - 2

Organization	Question 3:	Question 3 Comments:
AECC	Yes	It is good to see SPP go back to the original intent of Criteria 7.3.
Commonwealth Edison Co.	Yes	
Consumers Energy	Yes	
City, Water & Light	No	It appears that the way the standard is proposed, a system will be required to shed between 30% and 45% of its forecasted peak native load if the system drops to 58.7 hertz. This could be very difficult to achieve during off-peak conditions for systems that have wide load diversity. For example, shedding 30% to 45% of our predicted peak load during an extreme off peak situation, could result in shedding our entire load. This would be extremely complicated to regulate with our existing relaying. CWL drops main breakers of industrial circuits. To accomplish our load shedding, we trip only 6 main breakers. To trip 30% of our peak load during off-peak situations would require tripping 25 main breakers. Most of these breakers would require relay change outs at a great expense. CWL offers the following as a recommendation for load shedding requirements at various system load conditions. "Each utility will demonstrate their ability to shed load in three increments during peak conditions. The amount of load to be shed at each increment will be approximately 10 percent of the utility's previous year's peak load. The first increment will be shed at a frequency of 59.3 Hz, the second increment will be shed at 59 Hz, and the third increment will be shed at 58.7 Hz. It is understood by all parties (Utility & SPP) that the amount of load shed will be somewhat proportional to Utility's load at the time of the semiannual test or actual occurrence of a load-shedding event. This will significantly reduce the amount of load shed during low usage periods. Utility loads vary depending on the day of the week, on holidays, during downtime and during maintenance of facilities. The Utility will not be required to maintain an exact percentage of load shedding or an exact specific amount of load shedding at all times. Utility will initiate settings as specified above, to support the Regional System should an event occur. Load Shedding Testing of the Regional System will be conducted under the direction of SPP. The general guideline will

		be to test on a semi annual basis at a specific time and date at the discretion of SPP." Please provide examples to demonstrate this requirement/calculation of percentages of load to shed at on-peak and off-peak. If SPP continues to use a range for load shedding at the three UFLS steps, please consider increasing the Maximum Accumulated Load Relief Percentage.
SDT Response	**The intent of the UFLS standard is to require shedding 30-45% of the forecasted peak native load on that peak day only. In any day that is not a peak day it is understood that the amount of load shed will be less than 30-45% of native peak load and assumed to be somewhat proportional to the amount of native load at the time of the event. The standard drafting team agrees with your statement; "It is understood by all parties that the amount of load shed will be somewhat proportional to Utility's load at the time of the actual occurrence of the load shedding event." There is no requirement to prove any load shed amount by test. The requirements are to provide documentation of compliance to the standard.**	
Farmers' Electric Coop	Yes	My objection is not related to planning or operational basis, but the requirement that equipment and operations be mandated at the distribution level. This is currently accomplished and effective at the TO, TP, TOP, BA level.
SDT Response	**The existing SPP criteria is managed on a member basis (since each SPP member has agreed to follow the criteria) not on the basis of registered entities (TO, TP, TOP, BA). Therefore, each SPP member has agreed to shed load on their system as required to meet the criteria. The practical appli+cation of the existing SPP criteria in some cases results in a TO shedding load for a DP. The proposed SPP standard is designed to ensure that during a load shedding event the transmission system should remain intact as long as possible with load shedding occurring as close to the end user as practical. Therefore the proposed SPP standard requires that each DP be responsible for shedding its own native load.**	
Golden Spread	Yes	We support a planning based standard. An operational based standard would require dynamically arming and disarming UFLS relays. Many small entities do not have the resources or systems in place to perform dynamic arming and doing so would cause major expense.
KCPL	Yes	
KEPCO	Yes	
Lubbock Power & Light	No	Planning based standards are theory and not tested. Operational based standards have usually been tested and are true.
SDT Response	**The existing SPP criteria is an operational based standard in that it required demonstration that the entity could meet the criteria at any given time. The existing SPP UFLS criteria have never been tested by a real life region wide UFLS event. The effectiveness of the existing criteria on a region wide basis has only been confirmed by computer simulation. The proposed PRC-006-SPP standard was designed with the intent that all entities within the region will be able to comply with the requirements and still provide adequate protection for an actual UFLS event. The effectiveness of the proposed PRC-006-SPP standard will be confirmed by computer simulation just as the existing SPP criteria has been.**	
Nebraska Public Power District	Yes	
Occidental		No comment or position at this time.
OMPA	Yes	
SPRM	Yes	

SPS	Yes	
SWPA (Gary Cox)	Yes	
SWPA (Mike Wech)	Yes	I want to state that it is not that I necessarily disagree with this approach, but have some concerns that if this moves to a planning based standard, does that affect the ORWG involvement in review of the standard? Will several working groups continue to review this standard for applicability, conformance,and overall performance during UFLS events? I would assume so, but want to see how this affects the various working groups that currently look at the existing criteria.
SDT Response	**The existing criteria will not be in effect after this proposed standard is approved. The SPCWG is the standard drafting team for this proposed UFLS standard which is being developed per the SPP Standards Development Process so other working groups will not be involved in review of the standard. UFLS events will be reviewed by the Planning Coordinator based on information provided by all the involved entities as required by the proposed standard.**	

4. This standard proposes the intentional relay time delay for UFLS shall not be greater than 30 cycles. Do you agree with this approach? If not, please suggest why not?

Responses
Yes - 8
No - 7

Organization	Question 4:	Question 4 Comments:
AECC	Yes	There should be some intentional delay allowed. i don't think it needs to be less than 15 cycles.
AEP	No	30 cycles may to too high to support the steps described in R1.2.
Commonwealth Edison Co.	No	In general an intentional additional delay of 30 cycles seems too long to respond quickly enough to arrest declining frequency. It does seem reasonable to allow certain cases to have an intentional time delay such as large motors.
Consumers Energy	Yes	
City, Water & Light	No	CWL requests technical justification for this requirement. Could a bandwidth for the relay time delays be allowed for facilities that are close to the 30 cycles? Does “intentional” refer to the “programmable” or “settable” time delay offered by protective relays? Is the time delay only relay delay or total breaker clearing time?
Farmers’ Electric Coop		At the distribution level, I have no idea what approach is best, clearly, sufficient engineering analysis would be required for regional coordination of a UFLS program. It would appear that multiple participants increase the possibility of misoperation.
Golden Spread	Yes	We do not have technical justification for change.
KCPL	No	What is the engineering basis for 30 cycles? It is desirable to ensure no false trips will occur as a result of transmission or distribution system events that appear to the underfrequency relays to be an underfrequency condition and a half second is a very short time frame. Suggest the SDT consider establishing an engineering basis for a time frame that helps to minimize the risk of false trips and not so long as to endanger the integrity of the interconnect in an emergency situation.
KEPCO	No	We are neutral on this point because we do not own a UFLS system and have no experience to base a strong opinion either way.
Lubbock Power & Light	Yes	
Nebraska Public Power District	Yes	
Occidental		No comment or position at this time.
OMPA	Yes	
SPRM	Yes	
SPS	Yes	
SWPA (Gary Cox)	No	My question is where the 30 cycle figure came from. Is it a value that is from an engineering based study or just an arbitrary figure someone came up with, or because someone else is doing it.

SWPA (Mike Wech)	No	Would like to question the 30 cycle delay. If an entity has a 35 cycle delay, what is the technical justification for selecting a 30 cycle threshold? Any figure used should be based on a regions frequency response characteristic that is derived from studies of actual, or simulated events. Analysis of frequency degradation during an under frequency event and the frequency response characteristic provides the technical basis on which to set the time delay. My concern is that if there are entities in the system that have too much relay time delay and they now have to contract with someone to change the settings, where is the justification in that extra cost if they have conformed with SPP criteria in the past and had no prior issues?
SDT Response	**The goal in selection of the maximum time delay is to prevent triggering more UFLS stages than necessary to remove the generation deficit. Smaller time delays are acceptable and desirable as long as care is taken by the owner in setting the time delays to insure the UFLS relays will not misoperate for system faults or on circuits with heavy motor loads.** **The maximum delay is based on data from the "2006 Evaluation and Assessment of SPP Under-Frequency Load Shedding Scheme" dynamic UFLS study performed by Powertech, and calculations of expected rate of frequency decay using the equation of M=GH/180f megajoule-sec/electrical degree discussed in "Elements of Power System Analysis" by William D. Stevenson, Jr. Per these references, a 30-cycle delay plus 6 cycles of breaker clearing time is the maximum time delay for which an adequate margin is expected for the SPP steps.**	

5. **The standard proposes the Undervoltage inhibit shall be set as low as practical, but shall not be greater than 85 percent of nominal voltage. Do you agree with this approach? If not, please suggest why not?**

Responses
Yes - 9
No - 5

Organization	Question 5:	Question 5 Comments:
AECC	Yes	The approach is fine but I am not sure about the 85% of nominal.
AEP		We would request that nominal voltage be clarified to refer to primary or secondary voltage.
Commonwealth Edison Co.	Yes	
Consumers Energy	Yes	
City, Water & Light	No	CWL requests technical justification for this requirement.
Farmers' Electric Coop		At the distribution level, I have no idea what approach is best, clearly, sufficient engineering analysis would be required for regional coordination of a UFLS program. It would appear that multiple participants increase the possibility of misoperation.
Golden Spread	Yes	We do not have technical justification for change.
KCPL	Yes	Although there is no particular concern regarding the proposed 85% in the standard, what is the engineering basis for 85%?
KEPCO	No	We are neutral on this point because we do not own a UFLS system and have no experience to base a strong opinion either way.
Lubbock Power & Light	No	I think 80 percent is more realistic.
Nebraska Public Power District	Yes	
Occidental		No comment or position at this time.
OMPA	Yes	
SPRM	Yes	
SPS	Yes	
SWPA (Gary Cox)	No	Once again I want to know where the 85% figure came from and if it is what is needed in every area of the system from an engineering standpoint.
SWPA (Mike Wech)	No	Would like to question the undervoltage inhibit. If an entity has a setting outside of the limit, what is the technical justification for selecting 85%? My concern is that if there are entities in the system that are just outside this limit and they now have to contract with someone to change the settings, where is the justification in that extra cost if they have conformed with SPP criteria in the past and had no prior issues?

SDT Response	**Past studies of the UFLS program based on the SPP Criteria 7.3 have indicated the design to be sufficient. Unfortunately, the undervoltage inhibit language in the Criteria is somewhat vague. The Standard Drafting Team feels it necessary to provide more specificity in this area and basically polled the team members to identify a starting point felt to be acceptable - hence the 85% value. This value will also be part of the 2010 technical study and may be adjusted if technically warranted.**

6. The Standard Drafting Team has not set a specific timeframe for the implementation of the standard. What do you suggest for the implementation timeframe to comply with the proposed standard requirements?

Organization	Question 6 Comments:
AECC	3 years following approval at FERC minimum.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**
AEP	A phased-in approach is suggested.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**
Consumers Energy	Three to five years.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**
City, Water & Light	Please consider the actions required by all entities to gain compliance with the proposed standard. Allow ample time to implement processes and procedures to ensure compliance.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**
Farmers' Electric Coop	If implemented at the LSE and DP level, sufficient time would be required to purchase and install the necessary equipment and coordinate with the TO, TP, BA, and other LSE's DP's in the BA area. Since this is currently accomplished on a regional (BA) basis, I assume cost recovery is from all consumers using the system. If implemented at the LSE and DP level, would cost recovery of implementation and ongoing operational expenses be recovered from the larger SPP footprint, the BA level, or LSE and DP consumers?
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length. Cost recovery for installing the system is normally bore by the individual company, as a part of doing business. It will be brought up to others to see if there is any consideration to another way of cost recovery.**
Golden Spread	Golden Spread members are currently affected by UFLS via SPS relays installed at the transmission level. If "mutual agreement" were not reached, SPS would be required to remove UFLS from transmission lines affecting GS delivery points and GS members would be required to install UFLS on their systems. This would require significant equipment purchases and a coordinated effort between GS

	members and SPS. Golden Spread would suggest a five (5) year phase in period.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**
KCPL	Recommend the SDT consider 1 to 2 years considering the number of UFLS relays that could require settings changes to meet these proposed standards and the already committed manpower for relay maintenance.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**
KEPCO	Load Serving Entities have not been required to have UFLS programs in the past. If any LSE is required to install such a system (i.e. the option for a collective implementation by mutual agreement doesn't exist), enough time must be given for the LSE to budget for, plan and install such a system. A two year timeframe should be sufficient.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**
Lafayette Utilities System	At a minimum, SPP should delay issuing a proposed regional standard until NERC has completed its own consideration of a uniform continent-wide standard. Since November 2006, NERC has been engaged in the standards development process for a uniform continent-wide UFLS standard. On April 21, 2009, NERC posted for comment a proposed second draft of UFLS program requirements. In fact, based on comments NERC received during the first comment period, the NERC Standards Development Team decided to convert the originally proposed “Characteristics of UFLS Regional Reliability Standards” into a uniform continent-wide UFLS standard that will be adopted through the approved NERC standards development process. See http://www.nerc.com/docs/standards/sar/Stds_Announce_Comment_Pd_Project2007-01_UFLS_2009April21.pdf. If the new standard is approved, several existing standards will be retired, including PRC-006-0 — Development and Documentation of Regional UFLS Programs. Under these circumstances, it makes little sense for SPP to expend its own and stakeholders’ resources developing a regional UFLS standard. As some of the regions already have done, SPP should forgo further action on a regional UFLS standard until NERC completes its process of considering a uniform continent-wide standard. Only then can it be determined whether there are special regional concerns that need to be addressed. Even if it is eventually determined that an SPP regional standard should be considered, SPP has the burden of demonstrating that there is a compelling need to bring entities under the registration and compliance process that are not currently subject to that process. Specifically, to the extent that an SPP regional standard would apply to LSEs and GOs not otherwise required to be included in the NERC and SPP Compliance Registries, the proposed Standard may not be implemented until such time as SPP demonstrates (through engineering studies or similar analyses) that the reliability of the Bulk Electric System requires the inclusion of these entities (as well as that the proposed standard is otherwise permissible and within SPP’s authority to adopt). Stakeholders in the SPP region should have the opportunity to evaluate and comment on any such studies and/or analyses, and to challenge (if they wish) the conclusions SPP reaches from them.

SDT Response	**Because of the continued delays that NERC is having in developing a standard, and the change in direction that they now have had, SPP decided to move forward with the standard at the SPP level. From the direction that NERC is now taking, it is also felt that there will need to be a regional standard also, to accomplish the needed result. It is felt that once NERC has a standard, that the SPP standard will only need minor adjustments to bring it into compliance.** **SPP has been doing engineering studies on how the existing Criteria meet the needs of an UFLS program for many years. These studies are done every 5 years. These studies have validated the Criteria and the standard is being developed from this.** **What has been noted recently is that there are becoming more entities within the SPP footprint that are not members of SPP, but can affect the needed results of the existing Criteria. These are now being included into the standard.**
Lubbock Power & Light	I think due to the purchase and installation of relays that 2 years for the implementation might be sufficient.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**
Occidental	No comment or position at this time.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**
OMPA	First, OMPA feels the NERC standard should be finalized prior to finalizing the SPP standard to ensure consistency. If the current SPP draft is approved as currently written, the implementation timeframe to comply should be at least eighteen (18) months to ensure the smaller organizations have the opportunity to properly plan and budget for the equipment and installation necessary to comply with the requirements of this standard.
SDT Response	**It appears that the NERC standard will be some time in being finalized. SPP felt that the needs of a functioning UFLS require that SPP try and develop a standard now and in parallel with NERC, realizing that SPP may need to make some minor changes in the standard once NERC's standard is adopted.** **It appears that most feel a time frame of 24 months is what may be needed. The Drafting team will consider a time frame near that length.**
SPRM	For R1-R5 and R8 "At the beginning of the first calendar quarter 12 months after FERC approval."
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**
SPS	For highly interconnected systems where the interconnected companies do not participate via mutual agreement, there could be a lot of work required to separate the systems and avoid both companies attempting to interrupt the same load. For instance, if one company provides service to the other company at multiple locations, both companies may set up to trip common substations, resulting in less load being shed than anticipated. In these cases, a lengthy phase-in period would be warranted.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**

SWPA (Gary Cox)	I think 24 months like most everything else. It is only a thought.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**
SWPA (Mike Wech)	6 months after FERC approval.
SDT Response	**Thank you for your comment. It appears that a time frame of about 24 months seems to be about the average suggested. The Drafting team will consider a timeframe near that length.**

Additional Comments:

Organization	Comments:
AECC	***See comments at the end of the document.
AEP	R1.1 refers to 30% of forecasted peak native load for the current year. We would be interested in having a reference as to what constitutes this reference to "Native load," and as to whether this is the single highest peak for the prior year or some other measure of peak. **SDT Response: Native Load is defined in NERC Glossary of Terms…"The end-use customers that the Load-Serving Entity is obligated to serve." It is the forecasted highest peak of the next forecasted year.** What are the expectations with regard to how wholesale loads (particularly munies and co-ops, including TDU co-ops such as AECC, ETEC, NTEC, TEX-LA and similar situated entities) are to be counted in calculating forecasted load as the forecast relates to the proposed standard and the calculation of percentage of native load to drop in each step (R1.2). **SDT Response: Wholesale loads are to be counted in the same manner as other Native Load. Percentage of Wholesale loads are to be calculated in the same manner as other Native Load to be dropped as described in the standard.** Furthermore, how much wholesale load is to be dropped, assuming it is to be dropped, and how is it to be calculated? **SDT Response: The percentage of Wholesale loads to be dropped are to be within the boundaries as described in the standard. As expressed above, Percentage of Wholesale loads are to be calculated in the same manner as other Native Load to be dropped.** As a percentage of its member load ratio? **SDT Response: It shall be at least a 100% Percentage of its member load ratio.** A percentage of the co-op's own non-simultaneous peak forecasted load in AEP's control area? **SDT Response: No.** Will these co-op's be required to work out the details with regard to requirements posed by the standard? **SDT Response: Yes, each entity shall be required to work out these details or it shall properly delegate that responsibility.** Who will be held in noncompliance should a discrepancy arise and how will the penalties be allocated? **SDT Response: The entity shall be held in noncompliance in event that discrepancy arises. Penalties would be allocated according to its member load ratio.**

	Further requirements and measures will be necessary to provide the level of clarification that we are requesting. **SDT Response: Thank you for this comment. It is noted.**
Commonwealth Edison Co.	There should be a clear definition as to what constitutes a credible island, especially if the standard is calling for the installation of additional equipment in them. It is not clear what is meant in R7 where it is stated that UFLS capability should 'cover' potential imbalances. Do imbalances need to be covered 100%? There seems to be an inconsistency between who determines appropriate islands to study in R6 - the Planning Coordinator or the Transmission Planner.
SDT Response	**'Credible islands' has been defined in the Definition section.** **R6 and R7 have been revised.**
Consumers Energy	After R1.6, consider requiring a report of the details of any "Special Protection Scheme" (SPS) which impacts UFLS. The report to the Planning Coordinator must include the reason for the SPS, the amount of load involved, frequency settings, time delays, UV inhibit settings, and any other data required for proper modeling of the UFLS. While there may not be any relevant SPSs in SPP, there are some in the Midwest. In R2, the Generator Owner should be required to verify that the underfrequency tripping relays (including V/Hz) "will not trip during low frequency conditions above levels as listed in R1." Generating units have many problems with underfrequency. For example, on drum boilers, motor-driven boiler feed pumps run slower and thus pump less water at a time when MW demand, and thus steam flow, is likely to be increasing. This has resulted in unit trips on low drum level in response to underfrequency. Similar problems can occur with all motor-driven pumps, fans, coal pulverizers, etc. I believe there is no practical way, consistent with good utility operating practice, for a Generator Owner to "verify" that none of these things trip a unit on underfrequency. Absent a way to do this, the best that can be done is to require relay settings in accordance with R1. R6 is an excellent requirement. In R7, I suggest that in the first paragraph, replace the word "or" with "and". "Transmission Operator, Distribution Provider, Load Serving Entity, and Generator Owner....." I believe all of these entities should be required to participate. With the "or" in the sentence, one or more entities may decline to participate if one other entity is participating. In the second paragraph, the "or" seemed appropriate as it may be the responsibility of only one entity to install more UFLS. Thank you for the opportunity to comment on this well-thought out Draft Standard.
SDT Response	**"Special Protection Schemes" will be covered in a different standard.** **R2 and R7 have been revised.**
City, Water & Light	Each Generator Owner shall verify that their generating unit(s) will not trip during low frequency conditions above levels as listed in R1. Instead, CWL requests that registered entities shall verify that UFLS relays and generator protection equipment have been set to the levels identified in R1.2 and tested in accordance with applicable standards. **SDT Response: The intent of R2. in the SPP UFLS standard is that all generator frequency trip set-points be set below 58.7 Hz (and**

	we should simply state this in the standard to clarify the intent although we might want to set the threshold at 58.5 Hz) to ensure needed generation does not trip while the automatic load shedding program is attempting to arrest the frequency decline caused by lack of generation resources (more load than available generation). There is also a NERC SDT working on PRC-024 which is a Generator Verification standard. Their work is attempting to define an envelope within which "most" generators should be able to safely operate during both frequency and voltage excursions. The NERC UFLS SDT, SPP UFLS SDT and the NERC PRC-024 SDT are all working to coordinate their activities such that there are no conflicts. The SPP SDT appreciates the comment and is considering revising the language of R2 to more clearly state this requirement. CWL maintains that SPA, as the Balancing Authority, is the most likely Planning Coordinator for this transmission region. **SDT Response: SPP is the Planning Coordinator for the entire SPP Footprint by definition.** CWL requests a provision to allow for exceptions to noncompliance during times of emergency conditions such as loss of load during an ice storm or similar event. Also, CWL requests a provision to allow for exceptions to noncompliance during emergency or scheduled maintenance activities that result in the outage of UFLS relay equipment. Please see comments in number 3 above. **SDT Response: The intent of the SPP SDT is to transition from an operational based standard to a planning based standard. The previous operational based standard required that the steps be met any time (24 hours a day every day), regardless of time of year, circuit configuration, planned outages, etc. The new planning based approach is intended to require an entity to certify that the implemented load shedding steps are met at the forecasted peak. This will be the only "test" of an entities implementation from a compliance perspective. The belief is that even when the system is not operating at peak, the circuits involved in the shedding still make up essentially the same proportion of the total system load as they do at peak and therefore essentially the same percentages of the existing total load will be shed if an event occurs.**
Golden Spread	R4 states "Documentation shall include relay operational data and any associated event analyzing data from such devices such as fault, disturbance, or long term trend recorders associated with the UFLS event". Does this require a DP to install a fault recorder, disturbance recorder, or long term trend recorder? If not, GS would propose clarifying this with language such as "... and IF AVAILABLE any associated event analyzing data...".
SDT Response	**R4 has been removed.**
KCPL	• What does the reference to the NERC national standard in R5.2 add to the requirement? The requirement is sufficient in requiring a technical assessment of the UFLS effectiveness and the assessments should be done every 5 years or when significant changes dictate without the reference. This makes the document more manageable if the reference ever where to change. Recommend the SDT consider being specific regarding what is “significant changes” since “significant changes” is subject to interpretation. **SDT Response: Rather than reference the NERC standard that is not yet approved, propose changing R5.2 to include the performance characteristics from the NERC standard. “Significant changes” are those changes to the system that in the opinion of the Planning Coordinator could affect the ability of the UFLS program to meet the requirements of R5.2.** • Suggest the SDT consider an increase in the range of load shedding required in R1.2 in step 2 to 20 to 30% to make the range a straight line progression through the three steps, i.e. 5% - 10% - 15%. Step 2 at 20% to 25% may be too tight a range to accommodate the whole load

	spectrum. **SDT Response: The load percentage range for the first two steps have been increased.** • Recommend the SDT consider making it clear in R2 generators are not trip for frequencies 58.7 Hz and greater. The current language is a little confusing. Also recommend changing "verify" to "verify relay settings". Verify by itself could imply actual testing or other means that would be difficult to obtain or harmful to the operation of the generator in obtaining. **SDT Response: R2 wording has been changed to make it clearer about verifying the relay settings.** • R4.3 should be the responsibility of the Planning Coordinator or the Reliability Coordinator to determine root causes and contributing factors for a UFLS event. It is possible operating entities involved in an underfrequency event would not know the circumstances of the event. Consider those operating entities involved with the 2003 blackout that were a casualty of the event, but not the cause of the event. The way this is proposed, they would have to respond to what caused the event and they would not be in a position to do so. Recommend the SDT consider separating this as its own requirement and directed to the Planning Coordinator or the Reliability Coordinator. **SDT Response: R4 has been removed.** • What is the difference between "credible island" and "appropriate" in requirements R2.2, R6 & R7? How would "credible islands" be determined if not by design? Suggest the SDT consider replacing "credible island" with language that is specific to studying and applying islands by design that may be proposed by operating entities for consideration by the Planning Coordinator. **SDT Response: R2.2 has been removed from the draft. During actual UFLS events in the SPP area some islands have occurred. R6 and R7 are intended provide a way for the Planning Coordinator to include these islands in the system study.** • "Reliability Entity" is not a NERC defined term in R7. If the reference is intended to be the Planning Coordinator then it is recommended the SDT use that. If that is not the case, the SDT should use defined terms. **SDT Response: "Reliability Entity" has been removed from the draft.** • R8 reads more like a statement than a requirement. Suggest the SDT consider adding a requirement to R4 requiring operating entities to submit all data to the Planning Coordinator if R4 does not already require that and remover R8. **SDT Response: R8 has been removed from the draft.** • Recommend the SDT consider changing the compliance monitor reference from "Southwest Power Pool" to "Regional Entity". This would be more in line with Reliability Standard language. **SDT Response: Thank you for the comment. This change has been made.**

KEPCO	**Section 4.3** The proposed standard applies to LSEs with > 25 MW load. NERC registration criteria for an LSE states an LSE "peak load is > 25 MW and is directly connected to the bulk power (>100 kV) system". KEPCo recommends inclusion of the connectivity qualifier in the SPP reliability standard. **Section 4.4** The proposed standard applies to generator owners with "an aggregate nameplate rating of 10 MVA or greater". KEPCo recommends the NERC limits of 20 MVA for a single unit or an aggregate rating of 75 MVA. Section 4.4.1 still grants SPP the right to include other Generator Owners if the generating unit(s) is deemed crucial to reliability, in addition to the NERC registration criteria granting SPP that authority. **Section R1.1** Add a second sentence "In a collective implementation by mutual agreement of a single automatic UFLS program, the 30 percent value applies to the aggregate total load in the program." A Transmission Owner often does not trace load ownership for UFLS calculations, and the UFLS performance isn't dependent on each entity in a collective UFLS program sharing equal percentages of load. If members of the collective want equal percentages, they can address that in their agreement. **Section R3** This Requirement (to maintain UFLS data) applies to each entity listed in the Applicability Section. However, Requirement 1 allows for the collective implementation by mutual agreement of a single automatic UFLS program. In the first sentence, after the words Applicability Section, please insert ", or the designated entity for a collectively implemented UFLS program," **Section R4** This Requirement (to maintain UFLS operations info) applies to each entity listed in the Applicability Section. However, Requirement 1 allows for the collective implementation by mutual agreement of a single automatic UFLS program. In the first sentence, after the words Generator Owner, please insert ", or the designated entity for a collectively implemented UFLS program," **Section M1** Measure 1 deals with maintaining documentation that the UFLS scheme meets performance requirements and applies to each entity listed in the Applicability Section. However, Requirement 1 allows for the collective implementation by mutual agreement of a single automatic UFLS program. In the first sentence, after the words "their facilities", please insert ", or the designated entity for a collectively implemented UFLS program," **Section M3** Measure 3 deals with maintaining documentation of UFLS scheme program details and applies to each entity listed in the Applicability Section. However, Requirement 1 allows for the collective implementation by mutual agreement of a single automatic UFLS program. In the first sentence, after the words Generator Owner, please insert ", or the designated entity for a collectively implemented UFLS program," **Section M4** Measure 4 deals with maintaining documentation of UFLS scheme events and applies to each entity listed in the Applicability Section. However, Requirement 1 allows for the collective implementation by mutual agreement of a single automatic UFLS program. In the first sentence, after the words Generator Owner, please insert ", or the designated entity for a collectively implemented UFLS program,"

SDT Response	**Section 4.3** **This comment should be addressed with the new wording of section 4. "Distribution providers and any supplier with end-use load not registered as a Distribution Provider determined by the Regional Entity to have material impact on the Bulk Electric System," shall be included in the Applicability section.** **Section 4.4** **This comment should be addressed with the new wording of section 4. "Generator Owners and any owners of generation not registered as a Generator Owner determined by the Regional Entity to have a material impact on the Bulk Electric System," shall be included in the Applicability section. Small Generators may have a material impact on the Bulk Electric System.** **Section R1.1** **R1 discusses the option to "participate with one or more…To collectively implement by mutual agreement…" This comment should be addressed in R1 and further clarified with new wording.** **Section R3,R4,M1,M2,M3** **These comments are valid and should be inserted or covered in Draft 2. (Note: All deal with the same issue in different sections of the Standard.)**
Nebraska Public Power District	I didn't have any issues with the proposed philosophical changes. I had more issues with the language and that it was not very clear in some cases what was required. In R2, specify the frequency above which generators should not trip. There are 4 different frequencies listed in R1, which applies? Is it 59.3, 59.0, 58.7 or 58.5 Hz? You can argue that the generator should not trip above 58.7 Hz. There should be some time delay in the trip point to permit the UFLS to arrest frequency decline. If an islanding scheme expects the generator to be available to work, the unit probably shouldn't trip above 58.5 Hz. **SDT Response: Thank you for your comment. The SPP SDT agrees we should specify the exact frequency in which the generator should not trip at. The intent of R2 in the SPP UFLS standard is that all generator frequency trip set-points be set below 58.5 Hz to ensure needed generation does not trip while the automatic load shedding program is attempting to arrest the frequency decline. NERC UFLS SDT is working on a UFLS Continent Wide Standard which will require the Planning Coordinator to model all generator trip set-points that trip at or above 58.0 Hz. Simulated studies may reveal additional requirements for generator trip set-points between 58.0 and 58.5 Hz. The SPP SDT has revised the language of R2 to more clearly state this requirement.** R2.1 is not clear. I think what they are trying to say is that if you shed load to meet the R2 requirement, you need to shed at least as much load as the generator is generating at the same time the generator trips. Not sure what the last sentence about the non-dispatch generators means. Not sure that generator underfrequency protection is the same as UFLS. **SDT Response: Thank you for your comment. The SPP SDT has revised requirement R2.1** In R3, shouldn't the data be reported if it changes as well? **SDT Response: Thank you for your comment. The data submitted for R3 is only data required for the 5 year study. The**

	requirement allows the Planning Coordinator the ability to request UFLS data when the system changes or every five years to model the system. For example the system will change when Nebraska joins the SPP. The Planning Coordinator will be allowed to request UFLS data and model the system at that time. In R4, I believe the standard should address events where the UFLS operated as expected. I believe events where the UFLS either operated when it should not have or didn't operate when it should have should also be investigated. Not sure I see that requirement. In addition, there are a number of places in the Standard that state "Entities that participate with other Distribution Providers, Load-Serving Entities, or Transmission Owners by mutual agreement shall designate and report to the Planning Coordinator a single entity responsible for documentation of the UFLS event." This statement is not real clear. I think they want a single entity responsible for reporting for the combined group, but it is not worded very well. In R4.2.1, this is not very descriptive. What is the Electrical overview of system? Are they looking for generator outputs, power flows, outages, or what? **SDT Response: Thank you for your comment. R4 has been removed.** For R4.5, if the UFLS operated as expected, would there be any corrective actions? R6 appears to identify islands that may be what the rest of the standard refers to as "credible islands". If that is the case, it should state that these islands are credible islands. If not, the term should be defined somewhere in the standard. **SDT Response: Thank you for your comment. 'Credible Islands' has been defined in the Definition section of the Standard.**
Occidental	As currently written, if a generator is unable to or otherwise does not meet its under frequency requirement their additional need could be tacked on to the existing requirement on Loads in the area without penalty or effort on behalf of the generator. For example, if IPP ABC, owning a 500 MW combined cycle plant, fails to meet its under frequency requirement, the Loads existing on IOU XYZ's system could be involuntarily subjected to providing an extra 500 MW of under frequency relaying. This should not be the case. At a minimum if IPP ABC has not followed the rules then IPP ABC should be required to seek out Loads to voluntarily provide this service at some compensation level acceptable to those Loads. In no event should a Load be involuntarily placed on a UFLS in order to cover for a generator who has not followed the rules. Otherwise there is a disincentive for generators to properly maintain their own under frequency control systems, since they could inappropriately shift the cost and responsibility onto others by simply not maintaining or installing their own systems.
SDT Response	**The Standard Drafting Team agrees. R2 has been revised.**
OMPA	In addition to generator sizing concerns, the proposed SPP standard does not address controlling voltage during UFLS relay operations and the possible frequency overshoot condition. The proposed NERC PRC-006-01 standard describes these situations and the allowable limits.

SDT Response	**The SDT will discuss adding this to the SPP UFLS standard.**
SPRM	It is unclear if R1.1. requires entities to shed 30% of forecasted peak load on a 24/7/365 basis. If it is just for peak hour only, then it needs to state that. Suggested changes below.
SDT Response	**The intent is for the entity's installed UFLS equipment to be designed to shed the prescribed percentages of the forecasted peak load at the prescribed frequency steps. There is no requirement for an anytime "test". Several other similar comments have been received and the SDT appreciates your comment and proposed language modification. It is clear from the number of similar comments that this point needs clarification.**
SPP RE	The Risk Factor, compliance Monitoring Process, Violation Severity Levels and Implementation Plan sections neeed to be completed. Please involve Ron Ciesiel, SPP RE Executive Director of Compliance and Enforcement, in the working group efforts to draft these sections.
SPS	The table in R1.2 provides the requirement for minimum and maximum load relief at the various steps. This table, which matches the requirement in Section 7.3 of the SPP Criteria, shows for the second step that the minimum load relief shall be 20% with the maximum load relief of 25%. For the other steps, the maximum load relief is 50% higher than the minimum, but at the second step, the maximum load relief is only 25% higher than the minimum. This seems to require a much more accurate prediction of the load relief for those circuits include in this step. SPS would like to propose that for the second step, the maximum load relief be changed from 25% to 30%, to allow the same level of predictability as allowed in the other steps. In addition, consideration will need to be given to the complications that arise from the implementation of SmartGrid technology to insure that the UFLS program meets the UFLS standard.
SDT Response	**The table in R1.2 has been revised.**
SWPA (Gary Cox)	1. How should the DP/LSE/TO with automatic load shedding capability respond to industrial loads on UFLS circuits that may come off line for maintenance periodically, or are variable in nature? Also, this could apply to outages for maintenance or forced outages, as well; and may skew the UFLS dropping levels. 2. Need clarification on the language referring to UFLS being based on a Percentage of Forecasted Peak Native Load. If peak native load is forecasted to be 80MW, and during shoulder months they are at 30MW, won't this result in under tripping, or are they required to trip everything? Is this a moving target, where UFLS has to be continually changed? 3. Clarify "mutual agreement". Is this a written agreement?
SDT Response	**The intent of the 30% forecasted load requirement is to eliminate the current SPP criteria of 30% load at any given time. The drafting team understands that load profiles for different entities will vary and during the shoulder months of the year, an appropriate amount of load close to 30% for that time of the year will be shed, not the forecasted value. If a circuit is set up to trip for UFLS, the entity will not have to change to another circuit during circuit maintenance because the standard is for forecasted load.** **Yes, a mutual agreement should be written.**

SWPA (Mike Wech)	For Requirement 1: R1. Each Distribution Provider, LSE, and Transmission Owner with end-use Load customer(s) connected to their facilities shall implement an automatic UFLS program or shall participate with one or more Distribution Providers, LSE's, and Transmission Owners with end-use Load customer(s) connected to their facilities to collectively implement by mutual agreement a single automatic UFLS program. Entities that participate with other Distribution Providers, LSE's, or Transmission Owners by mutual agreement may designate and report to SPP a single entity responsible for compliance reporting purposes. After reading above...If several entities make up a UFLS program and they decide the host BA is the entity responsible for reporting, who is ultimately accountable/responsible for compliance with the single automatic UFLS program? Is each entity responsible? Is the reporting entity? There is no clear language that states who is ultimately responsible for R1. In order to make this truly enforceable, there needs to be clear definition of the responsibilities within the requirements. For Requirement 1.1 R1.1. Have the capability of automatically shedding at least 30 percent of forecasted peak native load for the upcoming year. I have some concerns that entities that participate jointly in an overall program may have trouble meeting this amount at all times due to the following type of scenario: A municipality has 50 MW of load that they shed at 59.3 HZ on a UFLS distribution feeder. They are doing maintenance work on this feeder and 30 MW of the load is transferred to another feeder that does not have UFLS. If an event occurs, they, nor the overall UFLS program are not going to shed enough load in that particular step. Are they non complaint since they were performing maintenance work and had load transferred off the feeder with UFLS relays? Specifically, who in the joint UFLS program in this case is non compliant? Is the whole group of mutual participants in the UFLS program non compliant?
SDT Response	**R1 will be revised to make it clear which entities are responsible for reporting.** **R1.1 The intent of the 30% forecasted load requirement is to eliminate the current SPP criteria of 30% load at any given time. The drafting team understands that load profiles for different entities will vary and during the shoulder months of the year, an appropriate amount of load close to 30% for that time of the year will be shed, not the forecasted value. If a circuit is set up to trip for UFLS, the entity will not have to change to another circuit during circuit maintenance because the standard is for forecasted load.**

Revised Regional Standard Language:

Organization	Comments:
AECC	See additional comments
AEP	R2 would be much clearer if a table or matrix be provided to identify responses to various operating conditions. R3 includes five entities and nine types of UFLS data. No one entity could provide all of this data, so it would be much clearer and successful to identify which entity provides which types of UFLS data. We suggest that an additional sub-requirement be added to follow R3.5 that would add "Breaker Operating Time" to the list of UFLS data. R4 should be entirely be deleted as the expectations are clearly included in the NERC Rules of Procedure. R7: Please add ". . . identified in areas of credible island, as identified in R6, shall participate . . ." Also, the expression "credible islanding" should be explained or introduced as a new term with a NERC definition. Additional Requirements and Measures necessary to support SDT's determinations from the issues posed in the "Additional Comments" section.
Lafayette Utilities System	4. Applicability 4.1 Transmission Owners 4.2 Distribution Providers 4.3 Load-Serving Entities 4.4 Generator Owners 4.5 Planning Coordinators 4.6 Transmission Planner
Occidental	R2. Each Generator Owner shall verify their generating unit(s) will not trip during low frequency conditions above levels as listed in R1. Should this not be practical due to the operating characteristics of certain units, the Generator Owner may become compliant by arranging for Load shedding to be installed by mutual agreement between the end-use Load customer(s) to provide the Load shedding. The Distribution provider, Load-Serving Entity, or Transmission Owner to whom the identified end-use Load customer is connected shall include the identified end-use Load customer(s) in its own UFLS, in addition to the required Load shedding as listed in R1.
SPRM	R1.1. Have the capability of automatically shedding at least 30 percent of forecasted peak native load for the current year during the forecasted peak hour.
SPS	SPS would like to propose inserting the word "system" to the term "native load" (so that it reads "native system load") whereever this phrase is used. This would include R1.1, the table in R1.2, R1.3 and R3.6. The intent of this change would be to make it clear that the forecast should be based on the system coincident peak, not the individual, non-coincident peak forecasts.

Comments
Of
Ronnie Frizzell
Arkansas Electric Coop. Corp.
On
SPP UFLS Regional Reliability Standard
PRC-006-1-SPP

Overall

1. Is this standard being written to comply with PRC-006-0 or the proposed PRC-006-1? If the intent is to have a SPP standard approved in any way by SPP, NERC or FERC PRIOR to FERC approval of PRC-006-1 then the SPP standard must be developed based on the existing FERC approved NERC Reliability Standard PRC-006-0.

2. There are some serious questions about PRC-006-1 being proposed at NERC. It is premature for SPP to develop a standard based on PRC-006-1.

3. The SPP standard should be written in a manner that if an entity is compliant with the SPP standard then it is also compliant with the NERC standard governing it. The standard in its current form does not accomplish this. It does not conform with nor does it include nor address many of the requirements in NERC PRC-006-1. It is clear that PRC-006-1 is moving in a different direction than the old programs such as the one outlined in SPP Criteria 7.3. If the intent of the drafting team is to design the SPP standard in accordance with PRC-006-1 then the proposed draft misses the mark.
a. The SPP standard does not address how the “group of Planning Coordinators” and their associated responsibilities as required in requirements R1 through R7 of PRC-006-1 will be accomplished.

4. A mapping document should be developed to show how each of the requirements in the NERC standards are being addressed in the SPP standard.

5. It is not clear which of the NERC standards, PRC-006-0 or PRC-006-1, the drafting team is using as a basis for the development of the SPP standard therefore it is very difficult to provide comments.

6. In many place the standard is overly wordy. Elaborate phrases are used where simple would be better.

7. There are portions of the standard that would be better if written in an application manual and not part of a standard.

8. Any reference to the "Planning Coordinator" should mean the "group of Planning Coordinators" as called for in PRC-006-1 and not individual Planning Coordinators. This group should be formed at SPP and have responsibility for developing documentation to define and explain how the SPP standard will be implemented, monitored, and compliance measured.

Number

9. Is the numbering scheme correct? I was under the impression that all NERC Standards version numbers come before the region. The NERC standard is PRC-006-0 shouldn't the correct numbering be PRC-006-0-SPP-0?
a. The NERC standards begin with a version 0. SPP should do the same. By beginning with version 1 it implies that there is an earlier version and is inconsistent with the NERC numbering convention.

Purpose

10. It is suggested that the purpose should be the same as the purpose of the NERC RS PRC-006-0 or PRC-006-1. The proposed purpose is too wordy and includes some phrases that are not appropriate
a. The phrase "Provide an adequate level of reliability…" is setting the standard up for a goal that the standard alone can not obtain. UFLS will contribute to improved reliability but will not in itself provide "an adequate level" of reliability.
b. "in accordance with a NERC UFLS Continent Wide Reliability Standard" should simple be stated "in accordance with NERC PRC-006-1". Again the question of which NERC standard the SPP standard is being developed to follow is unclear since PRC-006-1 has not yet been developed and approved.

Applicability

11. The SPP standard does not apply to the proper entities. The current applicable NERC standard PRC-007-0 applies to Transmission Owners (TO), Transmission Operators (TOP), Distribution Providers (DP), and Load Serving Entities (LSE) which are "required by its Regional Reliability Organization to own a UFLS program". The proposed NERC standard PRC-006-1 would apply to Planning Coordinators (PC), DP, and TOs with end use load.
a. R1 of NERC PRC-006-1 states that "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." The SPP standard should not apply to the Planning Coordinator but rather apply to the "group" that will be formed at SPP. This group is one that should be responsible for the PC requirements listed in the standard. The first requirement of the standard should spell out the details and responsibilities of the "group".

i. While the responsibility for development of a UFLS plan should lie with the LSE or DP, the "group" should be the ones responsible for any coordination of plans within and with other regions and ensuring that the SPP program is consistent with the programs of other regions.

b. The SPP standard shouldn't apply to a Transmission Planner (TP). The TP is not involved in the development of the plan in PRC-006-0, PRC-007-0 or PRC-006-1. The SPP standard does not contain any requirements applicable to a TP. An entity reporting to the TP does not make the TP an applicable entity.

c. There are no requirements in the NERC PRC-006-0, PRC-007-0 or PRC-006-1 which include the GO. PRC-006-1 purpose is "To establish design and documentation requirements for the automatic underfrequency load shedding (UFLS) programs…". Since the standard is written for load shed NOT generation shedding the standard shouldn't apply to Generator Owners. They have no load or the authority over any load.

d. The SPP Standard does not define who within the TO function is required to have an UFLS. The definition used in PRC-006-1 is a good start. Those TOs with ties between Balancing Authorities (BA) that are required to have a UFLS should be added.

e. The TOP is included in PRC-007-0 but are left out of the SPP standard completely. Are there any TOPs required to have an UFLS? If so TOPs should be included.

f. If the standard is to apply to LSEs then it should apply to ALL LSEs. The SPP program should be designed in such a manner as ALL LSEs can share equally the burden of load shedding.

12. One place the NERC PRC-0006-1 and SPP standard are completely missing the mark is that the LSE is not included. In many cases the LSE is the one that will own the relaying and have the responsibility for shedding load. By leaving them out the burden is placed on the DP which may or may not have anything to do with the actual shedding of the load.

13. 4.2.1 and 4.4.1 contain the phrase "may be required to register". The SPP standard has no authority to require an entity to register for anything and these sections should be removed. The Functional Model defines an entity responsible for a given function and any entity falling into that definition already has the obligation to register with NERC. The SPP standard exceeds its bounds by attempting to redefine who should register with NERC. The one thing the standard should do is make it clear WHICH registered entities within the entity registration should be required to have an UFLS. In other words, which DPs out of all of the DPs are required to have an UFLS? This is consistent with the applicability section of PRC-007-0.

a. The decision of who should register does not lie with the PCs or TPs for the same reasons stated above

b. One place where the standard misses the mark is that the standard should define how the "group" and not the PC or TP will determine which loads are crucial and "crucial" should be defined.

14. The definition of which DPs should have an UFLS is as simple as the definition for a LSE found in section 4.3.

15. If the standard is to apply to GOs it should simply apply to ALL GOs with an installed capacity in the same manner as R6.4.1 and R6.4.2 of PRC-0006-1.

Requirements

16. R1 should simply state that a DP, LSE, or TO required to have a UFLS will implement an automatic UFLS program and the program will include the following (R1.1 – R1.6). All of the other verbiage is either irrelevant here or needs to be put in a separate requirement.

17. R1 If the intent is to allow the aggregation of load from multiple entities into a single plan then simply state it in a separate requirement that such arrangements are permissible and provide guidance into what the agreement should contain.
  a. If the above is the intent then it should be a requirement that there be a written agreement to that affect signed by the officers of the companies involved. At a minimum this agreement should spell out the party which will be responsible for meeting all the responsibilities identified in the standard. The agreement could follow the same joint or delegation agreements that companies have for meeting other NERC standards.

18. R1 Concerning the phrase "with end-use Load customer(s) connected to their facilities". Is the word "their" referring to the TO or the DP, LSE, and TO as a group? If who is responsible for having an UFLS is well defined in the applicability section there is no need to repeat it here or elsewhere in the standard.

19. R1 states "… shall implement an automatic UFLS program …". There is no requirement that a plan or program be developed. The word "develop" needs to be included.

20. R1 should be rewritten to say: "The DP, LSE, or TO shall develop and implement an automatic UFLS plan and such plan shall include the following:". As written R1 directs the DP, LSE, and TO to implement a "program". The word "program" should be "plan". The "group" that will be formed at SPP is the one that should be required to have a program. The DP, LSE, and TO should be required to develop and implement a plan that meets the requirements of the SPP program.

21. R1.1 The design level of the plan is critical and the phrase "forecasted peak native load for the current year" causes some concern.
  a. By using the "current year", this could cause a problem with meeting compliance. Basing a plan on a current year forecast may not provide time for implementation of that plan before the current year peak period. This would require that a plan be based on the "current year" of a forecast that may have been done in the previous year. The use of an older forecast might not capture current load trends or topology changes. It is suggested that the drafting team consider plan development based on a "next year out" basis. This would mean

that during the current year the entity would be taking a forward look, have time to make adjustments and not be forced into using dated information.

b. The term “peak native load” does not clearly state the target load for which the plan should be developed and needs further definition. It is suggested that the definition once developed should be included in the standard in a similar manner in which definitions specific to standards are included in the NERC standards.

i. What is meant by peak? Summer? Winter? One hour? Average?

ii. What is meant by native? Firm? Firm+Non-firm? All load responsibility at the time of the peak?

22. R1.2 The establishment of windows is not consistent with the requirements of PRC-006-1 and puts some companies in an impossible position to meet compliance. By establishing windows the SPP standard will violate PRC-006-1 which calls for the regional program to have “consistent application across the region”. Consistent application implies that what is designed is also consistent in being attainable. The standard with windows is unattainable because it has created an impossible position for some to be able to meet compliance. The impossible position is due to factors such as the load mix and/or the amount of load versus the availability of sites for locating relaying which put some LSEs especially smaller LSEs in a position where either the minimum or the maximum can be met but not both. AECC has in the past adamantly opposed to use of maximum accumulated load limits in steps 1 and 2. AECC has argued and repeatedly shown that with the AECC load mix these limitations can not be met. SPP must realize the impact the creation of these narrow windows will place on ALL registered entities impacted by this standard especially small LSEs and LSEs with a special loads. If such windows are approved the drafting team is setting up a situation where some companies will be forced to ask for a waiver.

a. The SPP program should not impose a requirement that would require an entity to shed more load on a percentage basis than another entity in order to meet the requirements imposed by these windows. In AECC’s case it has been suggested that AECC shed more than 30% of its load in order to meet the window requirements of steps 1 and 2. It has been suggested that AECC design its plan in a manner that 30% of its non special load be shed in addition to the special loads. This is unfair, discriminatory, and should not be allowed.

b. The concern that too much load could be shed creating an over generation condition is not valid when you consider that the program is designed to eliminate such a condition by shedding load in 3 steps of 10% each.

c. AECC does not oppose an upper limit in step 3.

SDT Response: This Issue of Upper Limits was identified when the Drafting team began in 2008. Historically, the upper windows for step 1 and step 2 were added to the SPP Criteria around 2001 when wording was added to clarify “peak” in calculating the load shedding percentage. The windows for step 1 and step 2 were added in 2001 in an attempt to make the “at any given time peak” more flexible. In 2008 this subject was again discussed with the drafting team and left in the new standard.

The Power tech study looked at 15% over shedding with 30% Gen Loss and found over-freq acceptable and no Generation tripping due to over-speed. This supports the upper limit in step 3 which AECC does not oppose.

This Comment was further discussed and the upper limits for Step 1 and Step 2 have been raised in the 2nd draft.

23. R1.3 Anywhere the DP, LSE, or TO are referred to it should be clear that it is the DP, LSE, or TO that is responsible for having a UFLS. Not all DPs, LSEs and TOs or other entities may be required to have an UFLS. This caveat should be added after each reference throughout the doc.

24. R1.3 is not clear on what is being asked.
a. What is meant by "certify"? Is this a self-certification?
b. By "SPP region" do you mean the SPP Reliability Entity? Who specifically at SPP?
c. Does the drafting team want a certification of the percent of load which is planned or actually under automatic control?
d. The term "expects to automatically shed" should be "expects to have available for automatic load shed". It is not expected to actually shed load rather have load available to be shed.
e. By making the certification by April 1st implies that the intent is that the SPP program and all entities plans be based on the summer peak. If so, this should be clearly stated in the definition of "peak native load".
f. If the intent is to allow each entity to plan their program around their individual peak then April 1 doesn't work for winter peaking entities. Perhaps two certification dates are needed based on the entities peak. Summer peaking entities could report by April 1 and winter peaking entities by September 1.
g. Suggested rewording of R1.3: Each DP, LSE, or TO required to have an UFLS will self certify to the SPP Reliability Entity the percentage of forecasted load it has planned to be available under UF relay control for their current year peak. Summer peaking entities will report by April 1 and winter peaking entities by September 1 of each year.

25. R1.6 The requirement does not state to whom it applies. PRC-006-1 R5 places the responsibility for determining islands with the "group of Planning Coordinators". PRC-006-0 puts the requirement on the region. In the requirements that should spell out the organization of the "group of Planning Coordinators" and their functions is where this requirement should go.
a. A DP, LSE, or TO does not have authority over tie lines. Only a TO would have relays on a tie line and those would probably be put there at the direction of a Balancing Authority or Transmission Operator. This requirement applies to the "group of Planning Coordinators" under PRC-006-1 and should not apply to DP, LSE, or TO.
b. A Balancing Authority or a Transmission Operator is the one which deals with tie lines and their operation. This information would be crucial in the determination of islands. The standard however, does not apply to a BA or TOP by requiring there input or participation in determining islands. This is an oversight that needs to be included in the requirements which explain how the "group" will determine islands and not be a part of R1.

26. R2 The only requirement applicable to a GO is that it will ensure the under-frequency relays for their units be set to trip below the threshold frequency of XX Hz.

a. The frequency threshold whereby a generator will not trip needs to be defined in Hz and not be left subjective. How will the GO know if their unit will fail to meet R2 if a set frequency is not given? The threshold should be something below the frequency threshold for islanding, which is not defined either.

27. R2 Requiring GOs to contract with DPs or LSEs for load shed goes above and beyond what should be required in this standard. A standard should not require contractual agreements be entered into by an entity in order to meet compliance. How an entity chooses to meet compliance is the entities choice and should not be dictated. In addition, the LSE should not be obligated by a requirement to shed additional load in order to meet a requirement which applies to a generator. The LSE has met its obligation in requirement R1 and should not be burdened by shedding additional load. Again, the only requirement applicable to a GO is that it will ensure the under-frequency relays for their units be set to trip below the threshold frequency of XX Hz.

a. If there is a problem with a particular generator then that is the generators problem. If it can't be fixed then the generator should file for an exemption, the "group" study the impact and adjust accordingly

28. R2.1 It is unclear what is trying to be accomplished by this requirement. It does not make sense. Further explanation or clarification is needed.

a. Since generator dispatch is constantly changing the only way a generator could meet compliance is to have an amount of load shed equal to the generators total Mw output. This is unreasonable.

b. What does the "amount of generation interrupted by UFLS" for a non-dispatched generator mean? The amount of generation interrupted by UFLS will be the entire generator so the previous comment applies.

29. R3 should simply state that each DPs and LSEs plan will be updated at least every 5 years.

a. The words "listed in Applicability Section" should be removed. If the entities that the requirements apply to are properly defined then this wording is not needed.

b. The sub-requirements R3.1 to R3.9 should be included under either R1 or R5.

c. The data should be supplied to the "group of Planning Coordinators" not a single Planning Coordinator.

30. R3.1 to R3.9

a. R3.3 The device identification is of no value when you know the location. The "group" should only be interested in the clearing time of the device and that is not asked for.

b. R3.5 What is meant by the "Total Time Delay of each UFLS relay scheme"? Is this an overall design value which includes the intentional and unintentional relay delay or something else? If the intent is to get to the total delay from detection to clearing then the wording needs additional work and clarification.

i. "Total Time Delay" being capitalized implies a defined term. What is the definition?

c. R3.6 The requirement uses the term "Forecasted peak native load" which is inconsistent with the term "peak native load for the current year" used in R1.1. See previous comments concerning the definition of "peak native load".
d. R3.7 Again is the intent to get the total delay from detection to clearing?
e. R3.8 "Tie Line" as defined by NERC means a line between two Balancing Authorities. If this is the intent the only entity this requirement would apply to would be a TO who happens to own a Tie Line which is part of a UFLS scheme. The requirement should be made specific to those TOs. The DP, LSE, and GO are not involved in tie lines and will not have this information. If this is not the intent then "tie line" should be changed or defined. This requirement should be moved to the area dealing with Islanding.
f. R3.9 The same comment as for R3.8. The DP, LSE, and GO are not involved in Islanding schemes. This requirement should be move to the area dealing with Islanding.

31. R4 The TO, DP, GO AND LSE should be required to investigate and document events. The analysis of UF events requires the capability to run dynamic simulations which many TO, DP, and GO do not have or have the expertise to do. The "group of Planning Coordinators" should be the ones performing analysis. PRC-006-1 does not state who is responsible for analysis but by making the "group" responsible for developing and maintaining the database it implies that the analysis is beyond the capability of a single TO, DP, GO, or LSE. The TO, DP, GO, and LSE can not be expected to provide information concerning the configuration and operation of the system which is only known to the TOP or BA. R4 should be rewritten to say: Each TO, DP, GO, and LSE shall investigate and document UF events.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

32. R4 The documentation required by R4 should be that documentation the entity developed and is capable of providing as a result of their investigation. Much of what is being required deals with analysis of an event and is beyond what the TO, DP, GO or LSE can provide. The sub-requirements of R4 should be re-written to identify and include the things that a TO, DP, GO, or LSE are capable of providing. Details are included in later comments on sub-requirements R4.1 to R4.5.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

33. R4 Define "event"

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

34. R4 The wording "…that occur below the initiating set point of their UFLS program" should be removed. It is not an event unless this happens. If the drafting team wants this included then put it in a definition of "event".

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

35. R4 Each "shall" in R4 should be made a separate requirement. Shall investigate and document. Documentation shall include. Documentation shall be provided. These should all be separate requirements.

a. The documentation that will be required needs to be specific. Terms like "operational data" and "event analysis data" should be defined if there is going to be a requirement to provide it.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

36. R4 The second paragraph is problematic and should be removed.

a. Designating a single entity could create communication and data handling issues. Getting the data from anyone except by first hand will cause problems. The owner of the device which operated should be the one that directly reports to the "group".

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

b. This paragraph also defeats the benefit of groups working together. An entity may not be comfortable or unwilling to coordinate for others or an entity may be unwilling to let another entity act on its behalf. It is already required that events be reported. The entity that had the event should be the one doing the reporting.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

37. R4 By stating "The documentation shall include:" puts the TO, DP, GO, and LSE in an impossible situation for meeting compliance because much of the information being asked for in R4.1 to R4.5 is unavailable to the TO, DP, GO, or LSE and the "shall include" means the reporter has no option but to include something.

a. It is suggested that the statement be changed to say: The TO, DP, GO, or LSE shall provide available documentation including:

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

b. R4.1 to R4.5 describes what should be included in an event analysis. While the TO, DP, GO, and LSE can contribute, event analysis should be left to the "group". The TO, DP, GO and LSE should be able to provide a summary of what was found (R4.1), data concerning their relaying and its operation (R4.4), and corrective actions (R4.5) for events or portions of events that involve their UF relays and schemes. R4.2 and R4.3 require information that is beyond what the TO, DP, GO, and LSE can provide and these entities should not be responsible for R4.3 and R4.3.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

c. 4.2 The TO, DP, GO and LSE will not have this information. Only a TOP or BA will have information about the pre-disturbance system conditions. This should not be required of a TO, DP, GO, or LSE.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

d. 4.3 The information being required will come from multiple sources and should not be the sole responsibility of the TO, DP, GO, and LSE to compile and report. The TO, DP, GO, LSE and many other entities can contribute information but the determination is left to the "group" responsible for analysis.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

e. Since the TO, DP, GO, and LSE are not operating the system they will not be the ones that will necessarily know what initiated the event.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

38. R4.2, R4.3 and R4.4 should be included in documentation which should be developed and maintained by the "group" designed to define the SPP regional program and how it will operate and be removed from the standard.

a. It is understandable that the drafting team wants documentation that will allow for an adequate analysis of an event to be accomplished. The drafting team should use caution making sure the requirements apply to the proper entity and do not create situations where it will be impossible for an entity to meet a requirement. R4.2, R4.3 and part of R4.4 do just that.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

39. 4.3 Entities should only be required to report known data. A TO, DP, GO or LSE can only report the root cause, contributing factors, etc. that are known. 4.3 should be changed to say "Known Factors Initiating UFLS Events" and the sub-requirements have "Known" added to them.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

40. 4.3.3 It is not clear what this means.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

41. R4.4 the data requested in R3 is a separate issue from the detailed sequence of events. The "group" will already have the "data requested in R3" because they have the database. Anything not in the database is a violation of R3. Requiring data be provided twice is overburden.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

a. Suggested that "Detailed sequence of events" be changed to "Known details including the known sequence of events"

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

b. Suggested re-wording of R4.4: Known details including the known sequence of events and any other significant information which may be helpful in the determination of the cause, explanation of the event, or useful in determining corrective actions

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

42. R4.5 There should be a separation between the corrective actions taken immediately after an event, up to, and including the restoration of load and corrective actions developed post mortem as a result of an investigation.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

43. R4.5.1 Conclusions and recommendations are part of an analysis report and may not be known or developed until long after an investigation has been conducted. For an investigation report the requirement should be to include "known conclusions and recommendations" or "preliminary conclusions and recommendations".

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

44. R4.5.2 should be a stand alone requirement. Corrective actions identified as the result of an investigation or analysis of an event should be implemented and tracked until completed.
a. In order to track progress on implementation each corrective action might include a time line. Progress could then be reported on a quarterly basis.

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

b. Corrective actions and implementation progress should be coordinated and tracked by the "group".

SDT Response: Thank you for the comments. R4 has been removed from the UFLS standard since it is covered in EOP-004 along with some possible reporting requirements in the "Rules of Procedures."

45. R5, R6, R7, R8 Again any reference to the Planning Coordinator should mean the "group of Planning Coordinators" as called for in PRC-006-1 and not individual Planning Coordinators.

SDT Response: The Planning Coordinator will be established by the SPP Regional Entity.

46. R5 is a repeat of PRC-006-1 R8. The SPP standard should include any additional requirements which are specific to SPP or are more stringent than the NERC standard and not just repeat the NERC standard. Suggest this requirement be removed.

SDT Response: The intent of the drafting team is for entities to comply with the requirements of one standard on UFLS and not a mismatch of requirements between the continent wide and regional standard.

47. R5.1 first sentence. PRC-006-1 requires the database to be “annually maintained”.

SDT Response: SPP will require updated information every five years or as requested by SPP.

48. R5.1 The second sentence should simply say “The database shall include all the information identified in R3.” It does not need to repeat what is already included in another requirement.

SDT Response: This wording has been revised.

49. R5.2 should be a stand alone standard. The assessment is more than maintaining a database.

SDT Response: The Planning Coordinator will be held accountable to this requirement regardless of whether the requirement is a sub-requirement or not.

50. R5.2 “effectiveness of the design and compliance” of what? The individual entity plan? SPP program? SPP database?
a. How will an assessment of the effectiveness of compliance be conducted?
b. What does “significant changes in system conditions? Suggested that the sentence be ended with “as required” and delete the rest.

SDT Response: This requirement provides for a means for the Planning Coordinator to;

1. **verify the effectiveness of the SPP UFLS program and**
2. **verify the SPP Regional standard meets all of the continent wide requirements.**

The effectiveness of the SPP UFLS program will be determined by technical simulation. The wording "by significant changes in system conditions" has been removed.

51. R6 and R7 How islands are defined will be very critical. The SPP standard or the “group” documentation of how the SPP program is designed needs to be very specific on the criteria that will be used to determine islands. Islands should not be created and every attempt should be made to prevent forcing a DP or LSE to put additional load under UF control above and beyond what is required in R1.1.

SDT Response: Thank you for the comments. The Drafting team will consider this in any future work on the standard.

52. R6 is a repeat of PRC-006-1 R5. The SPP standard should include any additional requirements which are specific to SPP or are more stringent than the NERC standard and not just repeat the NERC standard. Suggest this requirement be removed.

SDT Response: The drafting team will review this suggestion. However, there is no approved NERC standard at this time and without it; all information will need to be in the SPP standard.

53. R6 The responsibility for determining islands lies with the "group" and not the TP. The TP may provide input into that determination but the TP should not be the one who deems an island appropriate. This is a delegation of responsibility specifically assigned to the "group" in PRC-006-1 R5.

SDT Response: First, the 'group' is in SPP's case SPP. In the present Criteria, the individual member of SPP may form an island if the system frequency falls below the third load shed frequency. The requirement is to coordinate this with their neighbors and to inform SPP of the plan. The drafting team has not identified a need for islanding as yet, but the first level may be to separate SPP from other regions and after that, allow individual members island, if this does not arrest the frequency decline. The drafting team will be considering this option.

54. R7 PRC-006-1 bullet 4 ensures that the entire region will be in at least one island. R7 then is requiring the TO, DP, LSE, and GO to participate in the assessment and mitigation that specifically address gen/load imbalance in the SPP region. Was this the intent?

SDT Response: See response to question 53.

55. R7 What is the definition of a "credible island"?

SDT Response: A 'Credible Island' is a geographical or electrical contiguous area that has the possibility and probability of having a balance of generations and load, and is separated electrically from other areas.

56. R7 What constitutes a generation/load imbalance? Is this the equation used in PRC-006-1 R6?

SDT Response: Yes

57. R7 concerning UFLS capability to cover generation/load imbalances refer to comments on R1.2 and R2.

58. R7 paragraph 2 any gen/load imbalance resulting from the creation of a new island should be identified by the “group” and each entity within the island participate on a load share basis. This should be spelled out in the requirement.

59. All of the functions of the “group of Planning Coordinators” should be spelled out in the requirement. The “group” is much more than a data processor.

SDT Response: In SPP there is no ‘group’ of coordinators. SPP is the Planning Coordinator.

60. M1 there are no performance requirements in R1. R1 defines the plan.

61. M2 see comments on R2

62. M4 The analysis is not the responsibility of the TO, DP, GO, or LSE. See comments on R4.

63. M5 There is only one group of Planning Coordinators. That group is responsible for the database.

64. M6 Under the NERC standards measures are what determine compliance. Measures should spell out specifically what will be measured and not generically refer to the requirement.

SDT Response to Questions 60-64: The drafting team will review these and make any needed adjustments.

65. The standard fails to address how the SPP program will address many of the aspects of PRC-006-1. Especially
  a. R1 no reference as to how the “group of Planning Coordinators” will be formed and their responsibilities carried out.
  b. R2 no reference as to how the program will be designed
  c. R3 no criteria for how islands will be determined
  d. R4 no reference to how the “group will coordinate with other regions
  e. R5 no criteria for how islands will be determined
  f. R6 no reference or requirements addressing the technical design parameters
  g. R7 no reference or requirements on how the “group” will conduct the UFLS assessment
  h. R9 no reference or requirement as to the schedule or format for supplying data

SDT Response: Until there is an approved NERC standard, it is hard to address specific statements in the proposed standard.

1. **Do you agree with the Step 1 and Step 2 maximum limits that were revised in the table in R1.1? If not, please provide a suggested revision.**

Responses
Yes - 5
No - 4

Organization	Question 1:	Question 1 Comments:
AECC	No	As AECC has stated on numerous occasions and in comments to previous drafts, limits on Step 1 and 2 are problematic and will place some entities in an impossible position of being able to meet the requirements. This is not only true for AECC but is quiet possibly true for smaller entities such as municipals and cooperatives. Please refer to AECC comments for Draft 1 for further explanation of AECC's position. AECC understands the drafting teams desire to limit the amount of load shed to ensure excessive shedding and is not opposed to a limit in Step 3 but not in Step 1 and 2.
SDT Response	**Thank you for your reply during the comment period for Draft #2. Requirement R1 has been revised in Draft #3 to accommodate some of the smaller entities. SPP will coordinate a UFLS study with Powertech to determine the validity of the three UFLS step ranges.**	
AEP	No	AEP is concerned with the structure proposed in this draft that employs participation as a "collective group" with a single entity reporting to the Planning Coordinator. Given the end-use Load relationship held by Distribution Providers, we believe that these entities (and other non-registered entities performing Distribution Provider responsibilities) are in the best circumstance to develop and administer UFLS programs. Transmission Owners should not be held accountable under mandatory reliability compliance for the non-response of other entities to a UFLS event when no formal delegation agreement exists. While it is appropriate for entities to have the option to create such formal relationships, a "collective group" should not be presumed to exist for each Transmission Owner. The maximum step sizes are rather large, and, in considering the allowed intentional time delay of up to 30 cycles, could result in excess shedding of load and unnecessarily high frequency. First, the step sizes need to be limited in size in order that a small load-generation imbalance just sufficient to trigger a step will not cause excessive load loss and high frequency. Secondly, the total delay time should not be so long as to result in the tripping of another step before the previous step has dumped its load and had a chance to arrest the declining frequency. Assuming a typical rate of frequency decline of .05 Hz/sec for every one percent imbalance, with ten percent steps and a .3 Hz increment between steps, our calculations show that total time delay should be limited to approximately 27 cycles.
SDT Response	**Thank you for your reply during the comment period for Draft #2. The Applicability Section has been modified and the changes will be presented in Draft #3.** **SPP will coordinate a UFLS study with Powertech to determine the validity of the three UFLS step ranges and to verify the**	

	intentional relay time delay of 30 cycles does not result in excess shedding of load.	
BPU	No	We are aware of at least one past request for waiver within SPP where the 58.7 hz had a maximum accumulated load relief of 50%; for our smaller system keeping with as wide a range (still up to 50% for 58.7 hz) may be desirable for ensuring future compliance.
SDT Response	**Thank you for your reply during the comment period for Draft #2. Requirement R1 has been revised in Draft #3. Also, SPP will coordinate a UFLS study with Powertech to determine the validity of the three UFLS step ranges.**	
Edison		
Golden Spread	Yes	
NextEra Energy (Florida)		
OMPA	Yes	
SPA	Yes	
SPRM	Yes	
SPS	Yes	
SUNC	No	Step 1 maximum should not be higher than Step 2 minimum in the table in R1.1. Overlap will cause confusion. Leave the same as in Version 1.
SDT Response	**Thank you for your reply during the comment period for Draft #2. Requirement R1 has been revised in Draft #3. Also, SPP will coordinate a UFLS study with Powertech to determine the validity of the three UFLS step ranges.**	

2. Do you agree with the definition of Forecasted Peak Native Load? If not, please provide a revised definition.

Responses
Yes - 6
No - 3

Organization	Question 2:	Question 2 Comments:
AECC	No	The definition needs to be clearer. Is this total coincident system peak load? **(Yes)** does it include firm, non-firm, interruptible loads? **(Yes, if they are "native load" (end-use customer load) as defined by NERC)**
SDT Response	**Thank you for your comment. Please see answers above and the following explanation.** **The "Forecasted Peak Native Load" definition has been removed from this standard based on the direction of NERC. The new terminology will be shown as "forecasted peak Native Load".** **"Native Load" is a term defined by NERC. It is defined as the end-use customers that the Load-Serving Entity is obligated to serve.**	
AEP	No	AEP concurs with the intent of the text provided in the applicability section 4.2 that states that "any other entity with end-use Load not registered as a Distribution Provider" that has a material impact on the BES should be responsible for compliance with this standard and for penalties of non-compliance. We would suggest that the Regional Entity not only identify these entities, but facilitate registration as a Distribution Provider consistent with the FERC's Functional Model. To this end, Although such entities are defined within the applicability of the standard, AEP is concerned with responses from the SDT to the first draft of this standard that AEP is to include "at least 100% of its member load ratio" for municipals and cooperatives in its Native Load calculations for purposes of its UFLS program. This response appears inconsistent with both the applicability section and with the SDT's response that cooperatives would be required to work out details posed by the standard or properly delegate that responsibility, subject to penalties being allocated on a member load ratio basis. It's also noteworthy that during the mock load tests that are conducted during the summer, these entities do participate independently and independently expected to determine its necessary load drop. Please assist us in reconciling these apparent inconsistencies.

SDT Response	**Thank you for your comment. The SDT's response to the first draft comments may have been more a misunderstanding of terms than anything else. In an attempt to clarify – it is the intent of this standard, as currently written, that an entity is only responsible for "native load" which as defined by NERC includes only end-use customers. Unfortunately, end-use customers are not defined. This term is taken by the SDT to mean the last 'party' to use the energy. Therefore, if your "customer" is a cooperative, municipal or similar 'utility', they are not the last user of the energy and therefore not an end-use customer. You are not responsible for their load unless an agreement is in place. Unfortunately, they may not be a registered entity, hence, one of the SDT's concerns is how to determine when this unregistered load is 'significant' and then how to address it with an unregistered entity.**	
BPU	Yes	We have had years where we may be off by around 5% in our forecasted peak native load. It is possible therefore to have error wherein our UFLS tripping may be a higher percentage than planned. The broad ranges will be helpful.
SDT Response	**Thank you for your comment.**	
Edison		
Golden Spread	Yes	
NextEra Energy (Florida)		
OMPA	Yes	
SPA	Yes	
SPRM	Yes	
SPS	Yes	
SUNC	No	We would rather see the term Forecasted Peak Native System Load used. This will make it clear that the forecast is based on the system coincident peak, not the individual, non-coincident peak forecasts. It is also consistent with the proposed definition in the standard.
SDT Response	**Thank you for your comment. The SDT's response to the first draft comments may have been more a misunderstanding of terms than anything else. In an attempt to clarify – it is the intent of this standard, as currently written, that an entity is only responsible for "native load" which as defined by NERC includes only end-use customers. Unfortunately, end-use customers are not defined. This term is taken by the SDT to mean the last 'party' to use the energy. Therefore, if your "customer" is a cooperative, municipal or similar 'utility', they are not the last user of the energy and therefore not an end-use customer. You are not responsible for their load unless an agreement is in place. Unfortunately, they may not be a registered entity, hence, one of the SDT's concerns is how to determine when this unregistered load is 'significant' and then how to address it with an unregistered entity.**	

3. In R2, generators will not trip during low frequency conditions above 58.0 Hz. Do you have any generators that cannot meet this requirement? If so, what is the minimum operating frequency?

<u>Responses</u>
Yes - 4
No - 5

Organization	Question 3:	Question 3 Comments:
SDT General Response	**Some commenters suggested there should be a time duration given for off frequency operation in R2 of the PRC-006-SPP-01 UFLS standard second draft. The standard has 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. R2 has been modified as shown below. The standard has been modified and R2 is now located at the bottom of the standard** **Each Generator Owner with individual generating units greater than 20 MVA (gross nameplate rating) or generating plant/Facilities greater than 75 MVA (gross nameplate rating) directly connected to the BES shall verify by review of relay settings, generator control system settings, and generator operating guides that their generating unit(s) will not trip above the Generator Under Frequency curve in Attachment 1 and will not trip below the Generator Over Frequency curve in Attachment 2. Should this not be practical due to the operating characteristics of certain units, the Generator Owner shall arrange for Load shedding to be installed in addition to that required Load shedding as listed in R3. NOTE: The three UFLS steps have moved from R1.**	
AECC		
AEP	Yes	• Three steam turbines cannot meet the requirement as currently proposed. The minimum operating frequency of these units is: at 59.4Hz for 180 seconds and at 58.4Hz for 30 seconds. • Four combustion turbines cannot meet the requirement as currently proposed. The minimum operating frequency of these units is: at 58.5 Hz for 2 seconds and at 57.0 Hz at 0.1 seconds.
SDT Response	**The SDT agrees there should be a time duration given for off frequency operation in R2 of the UFLS standard. The standard has 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. R2 has been modified as shown below.** **Each Generator Owner with individual generating units greater than 20 MVA (gross nameplate rating) or generating plant/Facilities greater than 75 MVA (gross nameplate rating) directly connected to the BES shall verify by review of relay settings, generator**	

	control system settings, and generator operating guides that their generating unit(s) will not trip above the Generator Under Frequency curve in Attachment 1 and will not trip below the Generator Over Frequency curve in Attachment 2. Should this not be practical due to the operating characteristics of certain units, the Generator Owner shall arrange for Load shedding to be installed in addition to that required Load shedding as listed in R3.	
BPU	No	Our Plant 3 Unit 1 generator, which is our newest generator, does not presently meet this requirement: it has a setting to trip at 58.5 hz with a 30 second delay. The original settings were by Black and Veatch engineering, and to date this has not caused a problem. We are interested in understanding why 58.5 hz would not still coordinate satisfactorily with the three stages of tripping of R1.1.
SDT Response	**The SDT agrees there should be a time duration given for off frequency operation in R2 of the UFLS standard. The standard has 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.**	
Edison	Yes	EMMT's current UFLS capability is for 58.5 Hz. EMMT is unsure if the wind generator turbines can run at the new setting, this will need to be studied by the OEM. EMMT would suggest a variance for existing facilities, and that facilities comply with the standards in place on market date. This new setting may cause generators to incur unreasonable expenses. What is the methodology driving this change?
SDT Response	**Will the modified R2 standard address your concerns? The SDT agrees there should be a time duration given for off frequency operation in R2 of the UFLS standard. The standard has 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. R2 has been modified as shown below.** **Each Generator Owner with individual generating units greater than 20 MVA (gross nameplate rating) or generating plant/Facilities greater than 75 MVA (gross nameplate rating) directly connected to the BES shall verify by review of relay settings, generator control system settings, and generator operating guides that their generating unit(s) will not trip above the Generator Under Frequency curve in Attachment 1 and will not trip below the Generator Over Frequency curve in Attachment 2. Should this not be practical due to the operating characteristics of certain units, the Generator Owner shall arrange for Load shedding to be installed in addition to that required Load shedding as listed in R3.**	
Golden Spread	No	
NextEra Energy (Florida)		
OMPA	Yes	Possible - not sure about those that are currently not required. It all depends on the SPP determination of which have material impact on the Bulk Electric System
SDT Response	**The SDT has modified R2 to address your concerns and eliminate the wording adverse impact.**	
SPA	No	SPA is not a Generator owner or Operator; however, R2 in the most recent draft references conditions above 57.8Hz , not 58.0 Hz as stated in question #3 of this comment form.
SDT Response	**Here is the current R2 requirement from PRC-006-SPP-01 draft 2.** **Each Generator Owner or generator identified in Applicability shall verify by review of relay settings, generator control system settings, and generator operating guides that their generating unit(s) will not trip during low frequency conditions above 58.0Hz. Should this not be practical due to the operating characteristics of certain units, the Planning Coordinator shall study the resulting**	

	loss of generation to determine if there is any adverse impact on the system. If there is an adverse impact, the Generator Owner or generator identified in Applicability shall be required to arrange for Load shedding to be installed by mutual agreement with Distribution Providers, Load-Serving Entities, and/or Transmission Owners with end-use Load customer(s) connected to their Facilities, in addition to that required Load shedding as listed in R1. **R2 is recommended to be modified as follows and has been renumbered in the standard:** **Each Generator Owner with individual generating units greater than 20 MVA (gross nameplate rating) or generating plant/Facilities greater than 75 MVA (gross nameplate rating) directly connected to the BES shall verify by review of relay settings, generator control system settings, and generator operating guides that their generating unit(s) will not trip above the Generator Under Frequency curve in Attachment 1 and will not trip below the Generator Over Frequency curve in Attachment 2. Should this not be practical due to the operating characteristics of certain units, the Generator Owner shall arrange for Load shedding to be installed in addition to that required Load shedding as listed in R3.**	
SPRM	No	
SPS	Yes	SPS feels this requirement is poorly written. A flat low frequency trip point of 58 Hz is unacceptable. As written, SPS would be required to operate its units indefinitely at any frequency above 58. Version 1 of this proposed standard stated that the generator owner could not trip a unit above the lowest load shedding value which is 58.7Hz (that is what is currently in the SPP Criteria that SPS operates to today). Currently, SPS has a two level trip scheme on all generator under-frequency relays in its system that operate with the following specs: 58.5 Hz with a 60 second time delay, or 57 Hz with a 2 second time delay. Values of this nature are common in industry and are used to protect the turbines. SPS believes that these values and time delays (or shorter) be adopted. If approved as is, there is the potential to catastrophically damage turbines and introduce significant safety hazards to the plants. To our knowledge, there are no turbine manufacturers that would allow indefinite operation at that level.
SDT Response	**The current standard would not require SPS to operate its units indefinitely at any frequency above 58 Hz. The states if generating units trip above 58Hz the Planning Coordinator shall study the resulting loss of generation. Here is the current R2 requirement from PRC-006-SPP-01 draft 2.** **Each Generator Owner or generator identified in Applicability shall verify by review of relay settings, generator control system settings, and generator operating guides that their generating unit(s) will not trip during low frequency conditions above 58.0Hz. Should this not be practical due to the operating characteristics of certain units, the Planning Coordinator shall study the resulting loss of generation to determine if there is any adverse impact on the system. If there is an adverse impact, the Generator Owner or generator identified in Applicability shall be required to arrange for Load shedding to be installed by mutual agreement with Distribution Providers, Load-Serving Entities, and/or Transmission Owners with end-use Load customer(s) connected to their Facilities, in addition to that required Load shedding as listed in R1.** **The SDT agrees with your recommendation and has modified R2 as follows:**	

	Each Generator Owner with individual generating units greater than 20 MVA (gross nameplate rating) or generating plant/Facilities greater than 75 MVA (gross nameplate rating) directly connected to the BES shall verify by review of relay settings, generator control system settings, and generator operating guides that their generating unit(s) will not trip above the Generator Under Frequency curve in Attachment 1 and will not trip below the Generator Over Frequency curve in Attachment 2. Should this not be practical due to the operating characteristics of certain units, the Generator Owner shall arrange for Load shedding to be installed in addition to that required Load shedding as listed in R3.	
SUNC	No	All our generators currently have proven trip points lower than 58.0 HZ.

Additional Comments:

Organization	Comments:
AECC	Section 4.2 (1) "any other entity" This term is unambiguous. The applicability of a standard needs to clearly state in unambiguous terms who the standard applies too. **"any other entity" has been removed from Section 4.2** (2) If the Regional Entity has determined that an entity has material impact on the Bulk Electric System then that entity should be registered with NERC as DP or LSE. **"any other entity" has been removed from Section 4.2** (3) This standard applies to Distribution Providers which are not directly responsible for load and not to LSEs which are. Why is the standard not applicable to LSEs? **In SPP, most DP's are also registered as LSE's. Also NERC Statement of Compliance Registry Criteria Revision 5, Section III.b.2 identifies the Distribution Provider responsibilities listed below.** **http://www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0.pdf** **III.b.2 Distribution provider is the responsible entity that owns, controls, or operates facilities that are part of any of the following protection systems or programs designed, installed, and operated for the protection of the bulk power system:** **• a required UFLS program.** **• a required UVLS program.** **• a required special protection system.** **• a required transmission protection system.** ***[Exclusion: A distribution provider will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, balancing authority, transmission operator, G&T cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]*** Section 4.2 Same comment as (1) in 4.2 R1 "end-use Load entities" This term is unambiguous. The requirements should also spell out very clearly who they apply too. The NERC functional entities should be specifically listed. **"end-use Load entities" has been removed from R1**

	R1.1 AECC is opposed to maximum limits in Step 1 and 2. **R1 has been modified.** R1.2 (1) "end-use Load entities" See comment for R1. (2) It is not clear what will be required by April 1. The program is based on the Forecasted Peak Native Load which is a projection for the upcoming year but this requirement is asking for a percentage based on a current year value. As I interpret this you are asking for example in April 2010 report 2010 load as a percentage of my 2011 forecasted peak. OR are you asking for 2010 load as a percentage based on the 2010 projection that was done in 2009? **Based on the latest load forecast, as of April 1 of the current calendar year.** R1.5 (1) "Applicable entities" See comment for R1. (2) Islanding Schemes are more of a transmission operations function rather than a Transmission Owner. The standard doesn't apply to Transmission Operators. In this respect the standard needs to apply to Transmission Operators. **Planning Coordinator will be responsible for determining islanding schemes activated before all three steps.** R2 (1) As AECC has voiced in its comments to Draft 1, the concept of forcing a Generator Owner to contract for load shed with another party is out of bounds for what should be required in a standard. It is questionable as to whether SPP would have the authority to do so. It would be expected that any attempt by SPP to force an entity to enter into any type of contractual agreement just to meet a standard would be challenged. **R2 has been modified. "Mutual agreement" has been removed.** **R2 is recommended to be modified as follows and has been renumbered in the standard:** **Each Generator Owner with individual generating units greater than 20 MVA (gross nameplate rating) or generating plant/Facilities greater than 75 MVA (gross nameplate rating) directly connected to the BES shall verify by review of relay settings, generator control system settings, and generator operating guides that their generating unit(s) will not trip above the Generator Under Frequency curve in Attachment 1 and will not trip below the Generator Over Frequency curve in Attachment 2. Should this not be practical due to the operating characteristics of certain units, the Generator Owner shall arrange for Load shedding to be installed in addition to that required Load shedding as listed in R3.** (2) The burden of this standard already rest primarily on the load. The DP will have met its obligations and should not be forced to suffer

	additional load shed responsibility due to a generator not being able capable of doing its part. At most the standard should recognize where these generators are and know the impact they will have on the BES. No program will be perfect. There may be areas where problems exist and mitigation not possible. Knowing these limitations and the impacts is part of the PCs job (R5). It is suggested that the definition of a "NON-Credible Island" be defined, these areas be identified, their impacts determined and if mitigation is possible be provided. **R2 has been modified. "Mutual agreement" has been removed.** **R2 is recommended to be modified as follows and has been renumbered in the standard:** **Each Generator Owner with individual generating units greater than 20 MVA (gross nameplate rating) or generating plant/Facilities greater than 75 MVA (gross nameplate rating) directly connected to the BES shall verify by review of relay settings, generator control system settings, and generator operating guides that their generating unit(s) will not trip above the Generator Under Frequency curve in Attachment 1 and will not trip below the Generator Over Frequency curve in Attachment 2. Should this not be practical due to the operating characteristics of certain units, the Generator Owner shall arrange for Load shedding to be installed in addition to that required Load shedding as listed in R3.** (3) What amount would the Generator Owner have to contract for? Full amount of the generation? **R2 has been modified and the amount of arranged load shedding is stated in the requirement.** R2.1 "This additional load shedding" Which additional load shedding? Unambiguous. **This additional Load shedding shall be equal to or greater than the maximum amount of generation <u>that can be tripped, instituted at the same frequency and time delays as the generator</u> would be expected to trip at and shall be within the same island.** R3 (1) "Applicable entities" Same comment as previously stated. Unambiguous term. (2) Some of this information is sensitive, such as that required in R3.2, and should only be provided subject to confidentiality. **Data submitted to the Planning Coordinator and their consultants will be kept confidential.** (3) SPP needs to realize that some entities reporting compliance to SPP may have to deal with Planning Coordinators other than SPP. There needs to be a requirement that based on having this information available PCs will do their job without preferential treatment and the the information will not be used for any purposes other than that for which it was supplied. **Information submitted to the Planning Coordinator and their consultants will be kept confidential and will not be used for any other purposes.** R6 As stated in an earlier comments, no program is perfect. Mitigation may not be possible. The standard fails to address how these situations may be handled in the event one should arise. **There is no waiver provision in the proposed standard; however, we have modified the standard to address some of these**

	concerns. M1, M2, M3, & M6 all contain unambiguous terms like "each ...... identified in Applicability", "designated entity" and "each applicable entity". Measures should be more specific in similar manner as requirements. **The measures have been updated to address the unambiguous terms.**
AEP	(1) Pursuant to Requirement 2, AEP supports the reliability need for the generator to review relay settings, generator control system settings, and generator operating guides to establish where their units will trip during low frequency conditions and advise the Planning Coordinator accordingly. However, the obligation imposed in Requirement 2 for the GO to arrange for Load Shedding to be installed by mutual agreement with Distribution Providers, Load-Serving Entities, and/or Transmission Owners with end-use load customers connected to their facilities is not a practical approach. Distribution Providers are required, per Requirement 1, to develop implement an automatic UFLS program. The Distribution Provider approach is the most suitable since these entities have an established relationship with customers from which program parameters and logistics may be defined and performed. Typically, the GO does not have such end-use customer relationships and cannot require such end-use customers to enter into load shedding agreements for UFLS events. **R2 has been modified as follows and mutual agreement has been removed:** **Each Generator Owner with individual generating units greater than 20 MVA (gross nameplate rating) or generating plant/Facilities greater than 75 MVA (gross nameplate rating) directly connected to the BES shall verify by review of relay settings, generator control system settings, and generator operating guides that their generating unit(s) will not trip above the Generator Under Frequency curve in Attachment 1 and will not trip below the Generator Over Frequency curve in Attachment 2. Should this not be practical due to the operating characteristics of certain units, the Generator Owner shall arrange for Load shedding to be installed in addition to that required Load shedding as listed in R3.** (2) The concept of the Planning Coordinator periodically conducting and documenting a technical assessment of the design of the UFLS "program" in Requirement R4.1.a. suggests that clarity be provided as to what specifically composes a "program." In what form? Written? Elements to be included? To what detail?, etc. It should also be noted that the reference to standard (PRC-006) may suggest that this requirement is duplicative and may need to be removed. **R4 has been modified to address this comment.** (3) For Requirement 3, AEP suggests that the phrase "As specified and documented by the Planning Coordinator," follow the leading subject "Applicable entities" and before "shall maintain . . . ." Such specification and documentation of applicable entities should include a determination of which entities are responsible for providing which of the 11 UFLS data items included in Requirement 3. Also, for compliance penalty purposes please provide the accuracy level intended for R3.1. Does the omission of a single relay from thousands represent a compliance violation? **R3 has been modified to address this comment.** **This will be addressed when the Violation Severity Level has been identified for each requirement.**

	Will the "number of UFLS relays installed" have a reliability purpose for the Planning Coordinator in the UFLS process? **No, this requirement has been removed.** (4) Please specify in R1.4 of the standard whether 85% of nominal voltage is "85% of nominal primary voltage" or "85% of nominal secondary voltage." **The undervoltage inhibit shall be set as low as practical, but shall not be greater than 85 percent of nominal voltage. Primary and secondary voltage should be the same.**
BPU	In general it appears the wide ranges, and the single reference point of forecasted peak native load, should be such that we can pick from our 15 reasonably available distribution circuits to meet compliance with R1.1 (in fact we do plan to use all 15 reasonably available circuits to meet this proposed standard). However, in the event that in the future we encountered difficulty summing to the required percentages, will there still be a means by which we could request a waiver - that is a formal exclusion from the requirement, with a different process to achieve the same criteria or standard goal, such that an approved waiver could be used for compliance evaluations? **There is no waiver provision in the proposed standard; however, we have modified the standard to address some of these concerns specifically the requirements for smaller utilities (Less than 100MW).** As an example of what may set us apart, we are a smaller utility and yet we serve one of three refineries in the state of Kansas. We do not plan to select any of the circuits serving the refinery as circuits to trip by UFLS as we believe fundamentally a purposeful trip poses a safety issue, and, recognizing that we do not have expertise to make this statement, it would seem to possibly also be a security issue. Thus we will be attempting to shed the same percentages of our load as other entities, but we will be working with a significantly reduced portfolio of available load to trip for under frequency. In addition, we serve two cities that are wholesale customers, and we hope to exclude the corresponding circuits from our UFLS as a trip would put an entire city out of electricity. Again, this reduces the load we have available to select from in designing a UFLS program for our utility. **SDT has revised Requirement R1 and created a new R3.2 to address your concern of being a small utility.**
Golden Spread	1. We continue to be concerned about the Applicability section, which appears to indicate that SPP wants to make the standard applicable to entities that are not registered for particular functional categories, but which SPP determines may nevertheless have an impact on the Bulk Power System. Pursuant to the Statement of Compliance Registry Criteria, if SPP believes an unregistered entity has a material effect on the BPS, SPP should require that entity to register for the appropriate function(s), subject to the entity's right to contest SPP's decision. SPP should not try to promulgate a standard that applies to unregistered entities. **The SDT has modified the Applicability Section. Words such as "any other entity" and "material impact" have been removed.** 2. The Implementation Plan is currently listed as TBD. Will this be sent out for comment when defined? Will the implementation plan address the phase in period for distribution providers that elect to install UFLS? **The implementation plan section is removed and detailed phase in approach is added in the Effective Date section to address this comment.** 3. The SPP needs to clarify if there are any additional requirements of a distribution provider that elects have existing UFLS removed by the transmission owner and installed on their own distribution facilities. **There will not be any additional requirements for the Distribution Provider.** 4. Will SPP further address the interaction and roles of each entity in the SPP region following a UFLS condition, or rely on PRC-009?

	PRC-009 will be retired after the NERC PRC-006 Continent wide standard is approved. In lieu of PRC-009, SPP SDT has added R6 in the latest SPP UFLS standard.
NextEra Energy (Florida)	NextEra Energy Resources wishes to thank the standard drafting team for their work on this important standard and hereby submits comments on the proposed PRC-006 SPP Regional Reliability Standard. Our comments focus specifically on two aspects of R2. (1) The term “adverse impact” appears in several areas of R2 with no clear definition for what it means. The term should be defined and the standard should clearly mandate that determination of “adverse impact” should be based on consistent, reasonable, and accepted engineering methods. The methods and outcomes should be available for review upon request by the regional entity and neighboring entities. **SDT has revised Requirement R2 and has removed the term “adverse impact”.** (2) R2 also states that the generator will be responsible for "arranging" for UFLS to be installed "..by mutual agreement with Distribution Providers, Load-Serving Entities, and/or Transmission Owners with end-use Load customer(s) connected to their Facilities, in addition to that required Load shedding as listed in R1." It is unclear how the generator is to arrange for this load shedding. What if the transmission owner or distribution provider refuse to shed load for a generator owner? What if they want compensation to shed load or even just to maintain the ability to shed this load if required? Generators do not have load to shed, and should not be involved in shedding load. If a generator has equipment limitations that prevent remaining on line during an under frequency event, then the TO or DP should be informed of these limitations. Generators should be required to have no tripping for under frequency inside the region described in the standard unless the generator can demonstrate that tripping must occur to prevent equipment damage. **SDT has revised Requirement R2 and has removed the wording “by mutual agreement with Distribution Providers, Load-Serving Entities, and/or Transmission Owners with end-use Load customer(s) connected to their Facilities”.** **The SDT has changed R2 from a single frequency trip point which would require a generator to operate indefinitely. The standard has generator underfrequency trip modeling curves and overfrequency trip modeling curves. These curves are the same as the proposed curves in PRC-024-1.**
OMPA	In the Applicability section of the draft standard PRC-0060SPP-01, 4.3 states “Generator Owners and any owners of generation not registered as a Generator Owner determined by the Regional Entity to have material impact on the Bulk Electric System.” What is the process that SPP will use for making this determination? Will it be documented? **The SDT has modified the Applicability Section to just “Generator Owners”**
SPA	R3 - (DT) R3.6 - In order to maintain consistency with the statements in R1.2 the statements in R3.6 should read: Total amount of calendar year forecasted peak native load shed by each trip frequency and the total amount of calendar year forecasted peak native load the entity has. **R3.6 has been modified.** R3.5 - How do you measure unintentional delay? **Unintentional delay can be obtained from the specification section in the relay manual. This may include relay process time and relay contact time.** R4 - Revise R4 to read: " The Planning Coordinator shall create and maintain an UFLS database. This database shall include all information identified in R3." **R4 has been modified.** R4.1 The Planning Coordinator shall periodically review the effectiveness of this Regional UFLS program according to the time lines provided in the FERC approved NERC PRC-006 Standard. **R4.1 has been modified.**

	(SWPA) - Shouldn't require the same thing in more than one standard. The time line is already identified in the continent-wide standard. Revise R5 to read: The Planning Coordinator shall determine if there are any islands that require study based on regional UFLS design or actual UFLS events. Revise R6 to R5.1 and do away with R6. R5.1 - Identified islands shall be analyzed by the Planning Coordinator and the affected entities to determine if any additional UFLS capability should be installed, and how that capability should be implemented. **R5 and R6 have been modified.**
SPRM	a. There is still some confusing language in the standard related to applicability that in my opinion isn't needed. The Applicability section and the Requirements should only state which Functional Entity the standard applies to. All other language trying to explain exactly which Transmission Owners, Distribution Providers, Generator Owners and/or Planning Coordinators should be handled during registration and/or the Compliance Monitoring and Enforcement Process. The SPP Regional Entity should know if it applies to a particular entity (currently registered or not) based on the results of the assessment required in R4. **The Applicability section has been modified.** b. Should M1 say "…evidence that its UFLS scheme meets the planning (instead of performance) requirements in R1."? **M1 has been modified.**
SPS	Please clarify that R1, R3 and R6 do not apply to the Generator Owner. **R1 and R3 would not apply to the Generator Owner. R6 would apply to all applicable entities in the island to include the Generator Owner to assess Generator/load imbalances, trip points, etc.** Under Applicability, SPS would like to see a clearer definition of which Generator Owners this standard applies to. The assumption is that the SDT is trying to capture wind generation attached to the distribution system. The previous version (version 1) had specific generation levels for units, or aggregate levels. **The applicability section has been changed to state "Generator Owners". Requirement R2 has been modified to identify which Generator Owners. R2 reads "Each Generator Owner with individual generating units greater than 20 MVA (gross nameplate rating) or generating plant/Facilities greater than 75 MVA (gross nameplate rating) directly connected to the BES…….."** SPS would also like to see a definition for "end-use Load entities". How these are identified is unclear, as well as how these entities would be held to compliance with this standard, especially if they are not a registered entity. **"end-use Load Entities" has been removed from the standard.** Under Applicability, how is "authorized" as a Planning Coordinator different than being registered as a Planning Coordinator? SPS would suggest using only the term "Planning Coordinator". **The applicability section has been changed to state "Planning Coordinator".**

	SPS would suggest that the requirements under R2 be broken out into separate requirements, to make measuring compliance more straight-forward. **R2 has been modified.** SPS would suggest eliminating R4.1 by incorporating the 2nd sentence in with R4. R4.1a should be made a stand-alone requirement, as it has no relation to either R4 or R4.1. **R4 has been modified.** SPS would like to see clarification as to who determines the "Credible Islands: **“Credible Islands” has been removed and the definition has been removed and the Planning Coordinator will identify any needed Islands** Under R5, it is unclear if the RC must share the results of the assessment with any other entity, and if so, what happens if the entity chooses to not take any action based on the assessment? **Yes the results would be shared. R5 has been modified and a new R1 and R2 created.**
SUNC	Applicability: 4.2 Extremely broad language essentially giving SPP authority for ANY load determined by the regional entity to have a material impact on the Bulk Electrical System. Need to be consistent with NERC Statement of Compliance Registry Criteria’s registration requirements for Load-Serving Entities (“LSEs”) or Generator Owners (“GOs”). Specifically, the Registration Criteria limit registration for LSEs to those entities having peak loads of greater than 25 MW and a direct connection to the Bulk Electric System or designated as the responsible entity for facilities that are part of required Under-Frequency Load Shedding (“UFLS”) or Under-Voltage Load Shedding programs. **The SDT has removed the wording “any other entity with end-use load” and “material impact on the Bulk Electrical System” from the applicability section.** 4.3 Same as 4.2. Extremely broad language giving SPP extraordinary powers over any generator determined by the RE to have material impact on the Bulk Electrical System even if they are not currently registered as a Generator Owner. **The SDT has removed the wording “material impact on the Bulk Electrical System” from the applicability section.** R5. An essential function of the Planning Coordinator. We have two utilities located inside our Balancing Area. Neither of them have generation to balance their native system load. At 58 HZ. our system would separate from the Bulk Electrical System and these two utilities load would have to be served by our generation. This requirement will study the situation and enforce additional UFLS tripping to assure the Credible Island remains stable. **Generator Under Frequency and Over Frequency curves were added to ensure performance characteristics are meet and frequency restored prior to 58.0Hz. A new requirement R1 was added for the Planning Coordinator to identify island(s) as a basis for designing a UFLS program and created requirement R2 which is the assessment and mitigation plan for the UFLS program.** R6. We applaud the intent of R6. The requirement is written concisely. Nice job by the drafting team on this one. **Thank you for your comment.**

1. **Section 3.2 has been added for entities that have a total forecasted Native Load less than 100 MW. Do you agree with this approach? If not, what would you recommend?**

Responses
Yes - 4
No - 1

Organization	Question 1:	Question 1 Comments:
AEP	Yes	
BPU	No	See comments at the end – I generally agree, but would also like the ability to request a waiver.
SDT Response	**The intent of the new standard is to eliminate any waivers and by making the standard flexible for all applicable entities to comply.**	
GSEC		We support this section if SPP can clarify that Section 3.2 does not apply to a Distribution Provider (DP) with less than 100 MW that has aggregated their load with other DPs. We believe that is the intent of R3.2, but Question 1 implies differently.
SDT Response	**All applicable registered entities will have to comply with the standard whether individually or in conjunction with others.**	
OMPA	Yes	Each entity should participate in the overall UFLS program. A generic 30% load relief level without specific frequency targets is admirable; however, such entities should shed load at each setpoint in R3.1; otherwise, the tendency could be to shed load only at 58.7 Hz.
SDT Response	**The Planning Coordinator, SPP, will determine the frequency targets and they may or may not be at all three set points.**	
NPPD	Yes	This will not affect our company since our load is much greater than 100MW. I see this as a benefit to both small and large load serving companies. This will require all UFLS PDP's and UFLS PTO's to shed their share of load. The companies with loads less than 100MW can load shed their 30% of their forecasted peak Native Load in one step verses 3 stages if they don't have the number of circuits to shed. The large companies will benefit by having the smaller companies shed their percentage.
SPRM	Yes	
SDT General Response	**Section 3.2 from the 3rd draft is now Requirement R2 from the 4th draft.**	

2. Can your generator frequency trip points meet Attachment 1 and 2 requirements or be modified to meet these requirements without endangering the generation equipment? If not, what are your limits?

Responses
Yes - 1
No - 3

Organization	Question 2:	Question 2 Comments:
AEP	No	As noted in previous comments on this standard AEP and other generator owners have some units that can not comply with the frequency operating requirements as written. These units have limitations prohibiting them from operating down to the low frequency trip points stated in the proposed standard. • Three steam turbines cannot meet the requirement as currently proposed. The minimum operating frequency of these units is: at 59.4Hz for 180 seconds and at 58.4Hz for 30 seconds. • Four combustion turbines cannot meet the requirement as currently proposed. The minimum operating frequency of these units is: at 58.5 Hz for 2 seconds and at 57.0 Hz at 0.1 seconds.
BPU	Yes	I am making an assumption that we could match this. Three of our four gas turbines do not have 81U underfrequency relaying at present.
OMPA		N/A - OMPA's generators are not directly connected to the BES; rather, they are connected at 69kV or lower voltage.
NPPD	No	Our company has one peaker plant, two coal plants, three gas turbine plants, and one nuclear plant that does not meet Attachment 1 or 2. The one peaker plant settings can be changed to meet requirement R8. The two coal plants will be forced into some form of modification. The only way to avoid a system modification at the plant would be to remove R8 from the standard. If R8 doesn't get removed the plant is looking at the costs for various modification options. Other than our issue with R8, we have no other concerns. The Standard is detailed enough that we can easily comply with it, which is an improvement over other standards. The three gas turbine plant settings can be changed to meet requirement R8. This is only possible since we have a microprocessor relay with multiple set points which can be set to meet R8 and meet turbine manufacture requirements.

		Here is the comments from our nuclear plant. The nuclear plant has potential consequences to the long term operation of the main generator below the existing setting of 58.5 HZ which is within the recommendation of IEEE STD C37.106. The turbine will be able to support the low frequency setting, but there will be long term degradation on the generator for running continuous outside recommended range of 98% to 102% of rated frequency. We will not be able to meet the new guideline for the over frequency trip, since our overspeed protection is set at 103% (1854 RPM equivalent to 61.8 HZ) and the new guideline recommendation is to set the protection above 62.2 HZ equivalent to 1866 RPM. Keep in mind that we don't have high frequency relay for trip protection, but we have overspeed protection. The overspeed protection is driven by the new turbine vendor guideline to prevent operation above 1854 RPM. We have a maximum of two hour of operating above the limit (accumulative) for the life of the LP and we already used about an hour of that time. Due to the new DEH modification we no longer need to overspeed the turbine above 1800 RPM for testing purpose and that is good, since we only have one hour left for operating above 103% (saved for potential future plant overspeed events). Does SPP have requirements on overspeed protection by non devices that are not relays? The current SPP criteria is stated as 58.5 Hz which match C37.106, what happens if we have manufacturer restrictions that will not allow us to meet attachment 1 or 2. We would like SPP to remove the portion of R8 that requires additional Load shedding shall be equal to or greater than the maximum amount of generation that can be tripped, instituted at the same frequency and time delays as the generator if the generator set points are not above attachment 1 or below attachment 2. The planning coordinator should first study if the generator will trip off line prior to making them shed load. We did not see any requirements in the NERC standard that the generator trips had to be outside the curves and that additional load shedding was required if they don't. This additional load shedding might be more aggressive load shedding then required. Can the PC modify the three stages of load shedding in the BA so the generator doesn't have to run outside manufacture requirments or trip additional load. Here is some limits on one of our machines: Mechanical resonance, under/over speed conditions and generic performance characteristics of steam turbines are listed below. These values vary between manufacturers and it should be noted that the durations are cumulative over the life of the turbine, not a single event. • Under/over speed condition of 1% will not damage turbine indefinitely (59.4/60.6Hz) • Under/over speed condition of 2% for 90 min could damage turbine (58.8/61.2Hz) • Under/over speed condition of 3% for 10 to 15 min could damage turbine (58.2/61.8Hz) • Under/over speed condition of 4% for 1 min could damage turbine (57.6/62.4Hz)
SPRM	No	City Utilities has some gas fired peaking turbinges that don't meet the curves. We have not determined at this point whether the relay settings can be adjusted without potential equipment damage. The settings of interest are at 58.0 Hz with 1.07 second delay (on Attachment 1 curve), 61.2 Hz with 20 second time delay (> 30 seconds required per Attachment 2 curve) and 61.8 Hz with 1.0 second time delay (on Attachment 2 curve).
SDT General Response	**The intent of R8 (now R7 in the 4th draft) is that all applicable entities contribute to the stabilization of frequency whether by maintaining generation or shedding load. If a generator is allowed to trip prior to the UFLS steps, then the trip could have a detrimental effect on system reliability.**	

3. Do you agree with revisions made to the Measures in support of the revisions to the Requirements? If not, what would you recommend?

Responses
Yes - 5
No - 0

Organization	Question 3:	Question 3 Comments:
AEP	Yes	AEP does not see any conflict in the Measures with respect to the Requirements. However, the Measures are very general and don't add much value.
BPU	Yes	
GSEC		We need clarification. Will all DPs, regardless of size, be required to have individual engineering assessments and mitigation plans per R2? If not, will DPs just participate with the Planning Coordinator (PC) and the PC will perform the engineering assessment and mitigation plan and then the PC would provide such results to the DP for compliance documentation for R2/M2?
SDT Response	**R2 has been removed from the 4th Draft.**	
OMPA	Yes	Need to clarify M2. Is the Planning Coordinator (SPP) responsible for initiating the Engineering Assessment? has the Assessment been defined?
SDT Response	**R2 has been removed from the 4th Draft.**	
NPPD	Yes	
SPRM	Yes	

4. **Do you agree with the Violation Severity Levels that were added to this draft? If not, what would you recommend?**

Responses
Yes - 5
No - 1

Organization	Question 4:	Question 4 Comments:
AEP	No	Overall, the VSL appear to be on par with the requirements. But, AEP has some comments regarding some of the draft requirements. Therefore, it would premature to address all of the Violation Severity Levels. We are reserving our comments until those requirements are addressed in a future draft.
BPU	Yes	
GSEC	Yes	
OMPA	Yes	Regarding R3.1 and R3.2 - What does it mean to "demonstrate"?
SDT Response	**The word “demonstrate” has been removed and replaced with more specific requirements.**	
NPPD	Yes	
SPRM	Yes	

5. **Do you agree that this standard is ready for Ballot? If not, provide specific suggestions that would make it acceptable to you.**

Responses
Yes - 1
No - 6

Organization	Question 5:	Question 5 Comments:
AEP	No	As we stated in the last draft, AEP questions if the the maximum step sizes are too large, and, in considering the allowed intentional time delay of up to 30 cycles, could result in excess shedding of load and unnecessarily high frequency. First, the step sizes need to be limited in size in order that a small load-generation imbalance just sufficient to trigger a step will not cause excessive load loss and high frequency. Secondly, the total delay time should not be so long as to result in the tripping of another step before the previous step has dumped its load and had a chance to arrest the declining frequency. Assuming a typical rate of frequency decline of .05 Hz/sec for every one percent imbalance, with ten percent steps and a .3 Hz increment between steps, our calculations show that total time delay should be limited to approximately 27 cycles. We understand that SPP is coordinating a UFLS study with Powertech to determine the validity of the three UFLS step ranges and to verify the intentional relay time delay of 30 cycles does not result in excess shedding of load. We recommend waiting until the study is finalized. With respect to Requirement 8 of this draft we have the following comments to offer. The requirement to "arrange for load shedding to be installed" still does not make sense to AEP and comments to that effect were also made by other entities. Units that are unable to comply with the standard are in many cases units that see very little operation and would likely be offline during a frequency excursion. "Arranging for load shedding to be installed" would in effect cause an excessive amount of load to be dropped since the units being compensated for would likely not even be in service. Units operate throughout the load range. How would anyone know how much compensating load has to be arranged for if this standard is approved as written? Would a generator have to "arrange for load shedding" based on full unit capability or some lesser amount? Again this would likely result in excessive load shedding.

SDT Response	**Through dynamic simulation SPP studied actual intentional time delays including the breaker time delays and did not identify any excessive load loss or high frequency. SPP is also studying a case if all UFLS relay delay times were set to 30 cycles including a 6 cycle breaker delay time. Allowing an intentional time delay of up to 30 cycles may improve system frequency response since some companies will need to lower their 30 cycles intentional time delays. Final dynamic simulations will be studied using actual operating times and excessive load loss and high frequencies will be evaluated.** **NERC PRC-006-1 standard has approved during its third ballot which contains generator trip modeling curves and performance characteristic curves. The SPP will adopt the NERC PRC-006-1 standard and its generator curves. The generator underfrequency curves were developed by the NERC PRC-024 and PRC-006 Standard Drafting Team. These generator curves were developed in conjunction with the Turbine Manufacturer(s). The SDT feels that the Generator Owners will be able to provide generator set points to meet the generator curves and still protect the turbine/generator(s) without having to provide additional load shedding.** **The intent of R8 (now R7 in the 4th draft) is that all applicable entities contribute to the stabilization of frequency whether by maintaining generation or shedding load. If a generator is allowed to trip prior to the UFLS steps, then the trip could have a detrimental effect on system reliability.** **R8.1 (now R7.1 in the 4th draft) states this additional load shedding shall be equal to or greater than the maximum amount of generation that can be tripped. The "maximum amount" will be based on full unit capability. SPP has studied excessive load shedding and verified the system frequency stayed within the NERC PRC-006-1 performance characteristic curves when subjecting the system to excessive load shedding.**	
BPU	No	BPU fully intends to abide by standards. SDT has revised R1 and created new R3.2, but BPU's forecast peak native load is 140 MW (well above 100 MW). While it appears we should be able to meet this standard, BPU is greatly concerned that there could be a future scenario wherein BPU could not meet the specified level without tripping all or a portion of the refinery or the local Manville insulation plant, BPU finds inherent safety concerns in willfully tripping either of these. BPU would like to see a revision to request a waiver for cases of security or safety.
Calpine	No	Regarding R8 and R8.1: Calpine wishes to thank the Standard drafting team for their work on this issue. We agree that there is a need for a coordinated underfrequency load shedding program and agree that early generator tripping can have a detremental effect on system reliability. We also agree that, if a existing generator cannot comply with the underfrequency performance requirements, shedding load in an amount equal to the lost generation is an effective solution. However, requiring owners of existing generation to arrange for load shedding places an undue burden on entities that have met all existing requirements for interconnection. Existing generation should be exempt from the requirement to arrange for load shedding by other entities. Non-utility Generator Operators do not have load to shed, and allowing an exemption for entities installing generators in the future that can arrange to shed load provides an unfair competitve advantage to such entities and reduces the future reliability of the Bulk Electric System by allowing otherwise avoidable load shedding. All new generation commissioned after the effective date of this Standard should be required to meet the frequency performance requirements of this Standard. We recommend the following change to R8 and M8 (Changes and deletions below in capital letters)

		R8. Each Generator Owner with individual generating units greater than 20 MVA (gross nameplate rating) or generating plant/Facilities greater than 75 MVA (gross nameplate rating) directly connected to the BES shall verify by review of relay settings, generator control system settings, and generator operating guides that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2. Should this not be practical due to the operating characteristics of certain EXISTING units, the (DELETE Generator Owner) ASSOCIATED TRANSMISSION OWNER OR DISTRIBUTION PROVIDER shall arrange for Load shedding to be installed in addition to that required Load shedding as listed in R3. [VRF: Medium][Time Horizon: Long-term Planning] 8.1. This additional Load shedding shall be equal to or greater than the maximum amount of generation that can be tripped, instituted at the same frequency and time delays as the generator would be expected to trip and shall be within the same island. M8. EACH GENERATOR OWNER IDENTIFIED IN R8 SHALL HAVE EVIDENCE THAT IT COMPLIES WITH THE REQUIREMENTS OF R8. WHERE EXISTING GENERATORS CANNOT MEET THE UNDERFREQUENCY REQUIREMENTS OF THE STANDARD (DELETE For each existing generator that cannot meet the underfrequency requirements of this Standard,) ASSOCIATED TRANSMISSION OWNER OR DISTRIBUTION PROVIDER (DELETE Each Generator Owner of generation shall have evidence that it complies with the R8 or) SHALL HAVE EVIDENCE THAT IT has made arrangements for additional Load shedding (DELETE, if appropriate,) as required in R8.
SDT Response	**The intent of R8 (now R7 in the 4th draft) is that all applicable entities contribute to the stabilization of frequency whether by maintaining generation or shedding load. If a generator is allowed to trip prior to the UFLS steps, then the trip could have a detrimental effect on system reliability.**	
GSEC	No	We need further clarification on the Section 4.2 (Applicability). The reference to “any provider” is not clear. “Provider” is not a defined term. Is this a continuing attempt to impose requirements on entities that don’t qualify as DPs under the Statement of Registry Criteria? If so, we continue to think it is inappropriate for SPP to try to impose requirements on entities that NERC has determined to not affect the BES. If that’s not what the reference to “any provider” means, then we simply don’t understand what it does mean, and it should be clarified or deleted. More discussion may be needed.
SDT Response	**This wording has been changed in the Applicability Section on the 4th Draft.**	
OMPA	Yes	
NPPD	No	R8 needs to address those units that can not meet attachment 1 or 2 based on manufacturer requirements and warranty issues with out requiring additional load shedding. Loading shedding studies in the area of these plants should be studied to see if faster trip times on stage 1, 2, and 3 or if different frequency set trip points other than 59.3, 59.0 or 58.7 can be used to arrest the frequencies prior to reaching the generator trip points. This would

		allow the PC to meet attachment 1 and 2 in the NERC standard draft.
SDT Response	**NERC PRC-006-1 standard has approved during its third ballot which contains generator trip modeling curves and performance characteristic curves. The SPP will adopt the NERC PRC-006-1 standard and its generator curves. The generator underfrequency curves were developed by the NERC PRC-024 and PRC-006 Standard Drafting Team. These generator curves were developed in conjuction with the Turbine Manufacturer(s). The SDT feels that the Generator Owners will be able to provide generator set points to meet the generator curves and still protect the turbine/generator(s) without having to provide additional load shedding.** **Through dynamic simulation SPP studied their UFLS scheme using actual intentional time delays including the breaker time delays. The current frequency set points of 59.3, 59.0, and 58.7 Hz has shown these frequencies are adequate to arrest system frequencies.**	
SPRM	No	Believe the Attachment 1 and 2 curves are overly restrictive and that previous UFLS studies indicate this. It appears that the lowest frequency in previous studies is approximately 58.4 Hz for about 1 second and highest frequency is about 60.2 Hz for about 1 second. Yet the proposed curves (1) Go as low as 58.0 Hz and require “ride-through” at 58.4 Hz for approximately 9 seconds and ; (2) Require “ride-through” capability well above apparent likely overfrequencies that the units will be exposed to. Recommend that these curves be adjusted to be less restrictive (less broad) as indicated by past studies. Perhaps the study currently being performed should be used to modify these curves.
SDT Response	**SPP completed an evaluation and assessment of the SPP UFLS scheme. Many UFLS cases were ran with some cases showing generator frequency approaching 58.0 Hz before recovering back to 60.0 Hz. Requiring a 2 second time delay at 58.0 Hz will provide “ride-through” time for the generator so the generator does not trip and allow the frequency to properly recover. Additional studies showed generator frequency below 58.4 Hz for two seconds. If a generator is allowed to trip prior to the UFLS steps, then the trip could have a detrimental effect on system reliability.** **NERC PRC-006-1 standard has approved during its third ballot which contains generator trip modeling curves and performance characteristic curves. The SPP will adopt the NERC PRC-006-1 standard and its generator curves. The generator underfrequency curves were developed by the NERC PRC-024 and PRC-006 Standard Drafting Team. These generator curves were developed in conjuction with the Turbine Manufacturer(s). The SDT feels that the Generator Owners will be able to provide generator set points to meet the generator curves and still protect the turbine/generator(s) without having to provide additional load shedding.**	

Additional Comments:

Organization	Additional Comments:
AEP	It appears that the SDT has addressed a number of our comments from the last draft. We commend the hard work of the SDT. However, AEP feels there are a few more outstanding concerns before this can proceed.
BPU	BPU historically is covered by Westar's UFLS. BPU is aware that waivers have been requested in the past as part of SPP UFLS program. Although the wider permitted % of load that can be tripped is helpful, BPU would still like to see a provision enabling a utility to request a waiver. BPU does not plan to trip safety/security related loads nor either of the two cities it serves. This means BPU is working with a significantly reduced portfolio of available to trip as we embark on a UFLS program.
SDT General Response	**The intent of the new standard is to eliminate any waivers and by making the standard flexible for all applicable entities to comply.**

1. Do you agree with the revision made to the underfrequency curve in Attachment 1? If not, what would you recommend?

Responses
Yes - 1
No - 1

Organization	Question 1:	Question 1 Comments:
AEP	No	The standard drafting team should replace the under frequency curve in Attachment 1 and reference the curves proposed by the NERC standard drafting team for PRC-024-1. The PRC-024-1 curves will set the standard for generator protective relays. AEP recognizes that SPP has an obligation under NERC standard PRC-006-1,pending regulatory approval, to include generator protection within this standard. If the SPP region requires a more restrictive curve than that proposed by NERC, the need for the additional restrictions should be clearly conveyed to industry.
BPU	Yes	This is out of my realm of expertise; I have no objections and this certainly looks reasonable to me.
NPPD		
SWPA		Southwestern is not a registered generator owner or operator, therefore we have no comment.
SDT General Response	**Attachment 1 is a generator operation curve developed by the SPP SPCWG to coordinate generator tripping with the dynamic simulation underfrequency results of the "2010 Evaluation and Assessment of Southwest Power Pool (SPP) Under-Frequency Load Shedding Scheme" prepared by Powertech Labs Inc. Adherence to this curve will help avoid aggravating an underfrequency situation by tripping additional generation.**	

2. Do you agree with revisions made to the Measures in support of the revisions to the Requirements? If not, what would you recommend?

Responses
Yes - 1
No - 3

Organization	Question 2:	Question 2 Comments:
AEP	No	See response to Question 4 with regards to replacing the existing Requirement 7 and its associated Measure.
BPU	Yes	
NPPD	No	R6 requires the GO to submit UFLS data however nothing in the Standard requires a GO to have a UFLS system. I recommend removal of R6 and M6. I also find it difficult to imagine a scenario of when a GO would have a UFLS system. Typically, a GO only provides power to the grid and would not have circuits suitable for tripping during an underfrequency event. If these types of circuits exist, the GO would be fulfilling the function of a UFLS Entity and should be registered accordingly. • Required load shedding equivalent to the plant's maximum generation if unable to meet the curves should be removed from R7.1 and M7. It is unknown whether or not this action will have a positive or negative impact on system reliability. I recommend revising R7.1 and M7 to require the GO to notify the PC when it is unable to meet the curves so that studies may be performed to determine the appropriate course of action. The GO would then be required to follow the recommended actions if any. This approach is consistent with the national standard.
SWPA	No	Please reference Southwestern's concerns in the additional comment field below. Depending on the drafting team's response to our concerns, Southwestern may have issues with the measures.
SDT General Response	**R6 has been revised in the 5th draft to require the GO's to submit their frequency trip point settings instead of their UFLS data as it was described in the 4th draft.**	

3. Do you agree with the Violation Severity Levels that were modified in this draft? If not, what would you recommend?

Responses
Yes - 1
No - 2

Organization	Question 3:	Question 3 Comments:
AEP	No	With respect to Requirement 4, there is no definition of year (i.e. calendar year vs year to date). This could have an impact of the VSL. See response to Question 4 with regards to replacing the existing Requirement 7 and its associated VSL. If Requirement 7 is not replaced, the existing VSL does not make sense. It states that noncompliance with three or more of the requirements results in a "severe" violation. However, the standard includes only one requirement and one sub requirement. This does not appear to fit with NERC's guidelines and at a minimum requires clarification.
BPU	Yes	I have not carefully scrutinized these but I certainly concur with the thought processes used.
NPPD		
SWPA	No	Please reference Southwestern's concerns in the additional comment field below. Depending on the drafting team's response to our concerns, Southwestern may have issues with the VSL's.
SDT General Response	**R4 has been revised in the 5th draft.** **R7 specifically mentions that generating units will not trip above the underfrequency curve in Attachment 1 and will not trip below the overfrequency curve in Attachment 2. Each of the attachments along with sub-requirement 7.1 make up the three possible violations listed in the VSL table.**	

4. **Do you agree that this standard is ready for Ballot? If not, provide specific suggestions that would make it acceptable to you.**

Responses
Yes - 0
No - 4

Organization	Question 4:	Question 4 Comments:
AEP	No	Requirement 4 appears to have a valuable assessment, but there is no expectation of communicating the results and follow-up if needed. There should be additional requirements (sub-requirements) that have the PC share the results with the UFLS entity and develop a corrective action plan to improve the referenced UFLS program. Requirement 7, as it appears in the draft standard should be removed. It is impractical if not impossible for the Generator Owner to arrange for load shedding. The requirement should be replaced with a requirement that, for existing units, the Generator Owner shall notify those responsible for the UFLS scheme of the generators ability to stay on-line and what point the operator of the UFLS scheme should expect the generator to trip. For units built after the standard becomes effective, a requirement for the unit to remain online within the curve would be acceptable. Replacement of the existing Requirement 7 would necessitate the removal of the existing Measure 7 and associated VSL. A new measure and new VSL would need developed for the replacement requirement.
BPU	No	My sole objection remains that there is no recourse for a smaller entity such as BPU if the required load shed steps themselves posed a reliability risk. At one of the December Webinars I found it especially interesting that a comment was made that tripping an entity such as a refinery would be counter to the entire thrust of the NERC reliability standards. BPU serves one of three refineries that I know of remaining in Kansas, and before applying this regional standard we will first remove from our load profile the refinery and Manville insulation plant. After that we apply the standard to our remaining percentage of load. At present we will be able to meet this standard, but if in some future year we could not meet this, then there is no mechanism by which we could plead the problem. Please refer to our earlier comments for more complete explanation.
NPPD	No	R1 states that each UFLS entity that has a total forecasted peak Native Load greater than or equal to 100 MW shall develop and implement an automatic UFLS program meeting certain requirements. Since only Load Serving

		Entities and Distribution Providers serve Native Load, it appears only these two registered functions are required to have an automatic UFLS system meeting certain requirements if they meet the 100 MW threshold. For example, a TO or TOP does not serve Native Load therefore they are not required to have an automatic UFLS program regardless of the energy flow on their system. I recommend revising the criteria to better reflect those entities that actually own, operate or control UFLS equipment. • R2 states that each UFLS entity that has a total forecasted peak Native Load less than 100 MW shall develop and implement an automatic UFLS program meeting certain requirements. Since only Load Serving Entities and Distribution Providers serve Native Load, it appears only these two registered functions are required to have an automatic UFLS system meeting certain requirements if they do not meet the 100 MW threshold. For example, a TO or TOP does not serve Native Load therefore they are not required to have an automatic UFLS program regardless of the energy flow on their system. I recommend revising the criteria to better reflect those entities that actually own, operate or control UFLS equipment. R1.3 and R2.4 includes undervoltage inhibit restrictions. These requirements are not clear as to what is being inhibited. I recommend changing R1.3 and R2.4 to clearly define what is being inhibited. I also question the appropriateness of including undervoltage limitations in an UFLS standard. • R4 requires the PC to perform an assessment to determine if the UFLS program meets R1 and R2. These requirements only state how much load must be tripped and when. Nothing in R4 requires the PC to evaluate the effectiveness of the UFLS program to mitigate an underfrequency event. In addition, noting in R4 requires the PC to establish a coordinated UFLS program of all UFLS entities for which the PC is responsible. I recommend adding sub-requirement to: 1) Establish a coordinated UFLS program in accordance with PRC-006-1 of all UFLS entities for which the PC is responsible; and 2) Evaluate the effectiveness of the coordinated UFLS program to mitigate an underfrequency event when performing the assessments. • R6 requires the GO to submit UFLS data however nothing in the Standard requires a GO to have an automatic UFLS system. I recommend removal of R6 and M6. I also find it difficult to imagine a scenario of when a GO would have a UFLS system. Typically, a GO only provides power to the grid and would not have circuits suitable for tripping during an underfrequency event. If these types of circuits exist, the GO would be fulfilling the function of a UFLS Entity and should be registered accordingly. • Required load shedding equivalent to the plant's maximum generation if unable to meet the curves should be removed from R7.1 and M7. It is unknown whether or not this action will have a positive or negative impact on system reliability. I recommend revising R7.1 and M7 to require the GO to notify the PC when it is unable to meet the curves so that studies may be performed to determine the appropriate course of action. The GO would then be required to follow the recommended actions if any. This approach is consistent with the national standard. • The draft Implementation Plan document is not consistent with the Effective Dates contained within the draft Standard. Specifically, the document states that R4 becomes effective in 1 year and all other Requirements

		effective in 3 years. The draft Standard states R4, R5, and R6 shall become effective in 1 year and all other Requirements effective in 3 years. I recommend changing the implementation plan document to be consistent with the draft Standard. • The draft Implementation Plan document states the one year phase in for compliance is needed for the PC to perform the studies necessary to assess the effectiveness of the UFLS program. However, the draft Standard does not require the PC to perform an assessment of the effectiveness of the UFLS program. I recommend revising the Implementation Plan document to state the one year phase in for compliance is needed for the perform the assessments required by R4. • The draft Implementation Plan document suggests that it is acceptable to implement an aggregated UFLS program with other UFLS entities. However, nothing in the draft Standard allows such an aggregated UFLS program. I recommend removing the option for an aggregated UFLS program from the Implementation Plan document. Compliance enforcement is very difficult when a group of organizations are responsible for compliance. Which entity of the group would be held accountable if R1 or R2 was not met? Would one entity of a group be held accountable for the non-compliance even if they exceeded R1 or R2?
SWPA	No	Please reference Southwestern's concerns in the additional comments field below. Depending on the drafting teams response to our concerns, Southwestern has issues with this standard being ready for balloting.
SDT General Response	**R6 has been revised in the 5th draft to require the GO's to submit their frequency trip point settings instead of their UFLS data as it was described in the 4th draft. The Implementation Plan has been revised to reflect the correct effective dates.**	

Additional Comments:

Organization	Additional Comments:
AEP	
BPU	We have been told that it is intended that we should expect, in order to comply, that we may have to trip entire communities (we provide wholesale electricity to two cities), and that we should expect that we may have to trip our hospital. We have conflicting information that apparently we may have to expect to trip portions of a refinery possibly posing significant environmental and safety issues, yet we have clearly heard in December 2010 that it would be contrary to NERC standards for us to trip an entity such as a refinery. We can envision a future scenario in which we would not be able to have it both ways. We can more readily envision a scenario in which we have to add breakers and substations – go to considerable expense – to be able to comply.
NPPD	The Background Information identifies 5 major objectives of this Regional Standard. Objective #3, coordination between the UFLS program and generator trip settings, is not addressed in this draft Standard. The draft Standard does not require the PC to develop an area-wide coordinated UFLS program. R1 and R2 requires UFLS entities to develop UFLS programs and R7 requires GOs to report generation trip settings. However, R4 only requires the PC to assess whether or not the UFLS program satisfied R1 or R2. It is not clear which UFLS program is being assessed since there is no requirement in this Standard to develop an area-wide coordinated UFLS program in accordance with Standard PRC-006-1. I recommend adding a new Requirement to the Standard for the PC to develop a coordinated area-wide UFLS program taking into consideration each UFLS entity UFLS program and each generator trip settings. An alternative would be to delete R4 since PRC-006-1 R4 already requires the PC to perform an area-wide assessment that takes into consideration generator trip settings. Objective #4, ensure appropriate requirements are followed after an UFLS event, is not addressed in this draft Standard. I recommend either deleting the objective or developing a Requirement such as performing post-event assessments of the effectiveness of the UFLS programs (both UFLS entity and area-wide UFLS programs) and the performance of the UFLS equipment. The post-event assessment should also include any recommended improvements. Objective #5, ensure that the standard is enforceable with clearly defined requirements and unambiguous language, was not accomplished in my opinion for the following reasons: 1) R1 and R2 establishes the selection criteria of who must develop and implement an automatic UFLS program based on forecasted peak Native Load. Since only LSEs and DPs serve Native Load, registered functions such as TOs and TOPs who own, operate or control much of the UFLS equipment are not included. 2) R1.3 and R2.4 includes undervoltage inhibit restrictions. These requirements are not clear as to what is being inhibited. I recommend changing R1.3 and R2.4 to clearly define what is being inhibited. 3) R4 requires the PC to perform and document a UFLS technical assessment to determine that the UFLS program meets Requirements R1 and R2. It is unclear which UFLS program must be assessed. Is it each UFLS entity's UFLS program or is it the

	PC's UFLS program required by PRC-006-1? Is it the automatic UFLS program, manual UFLS program, or both? 4) The data required by R5 is ambiguous. For example, 5.1 asks for the location of installed UFLS equipment. Is this the substation name, or the circuit name, or breaker designation, or even the control panel the relay is located within? Would I be compliant if I stated the UFLS equipment is located in Nebraska? 5) It is unclear why R6 specifically identifies the GO to provide UFLS data to the PC. If the GO owns, operates, or controls a UFLS program, wouldn't they be included as a UFLS entity? I recommend deleting R6. 6) R7 Part 7.1 requires additional Load shedding to be equal to or greater than the maximum amount of generation that can be tripped. Is this a dynamic maximum or nameplate maximum. For example, if a 600 MW generator is operating at 250 MW and a frequency event occurs, is 600 MW or 250 MW required to be tripped? If it is the nameplate value, will this create an unintended consequence to the reliability of the BES?
SWPA	Southwestern appreciates the SDT's efforts in development of this regional standard, and its need to coordinate with the development of NERC's continent-wide standard; however, Southwestern has concerns with 4.2 of the Applicability section as revised. Southwestern believes that the Distribution Provider, as the entity that connects end-user load (Native Load) to the electrical system, has primary responsibility for implementing UFLS; this is reinforced by the NERC Functional Model. While some Transmission Owners implement UFLS, either because they are vertically integrated or have contractual arrangements with DPs in their area, the revised 4.2 language implies that the Planning Coordinator may impose a requirement upon a Transmission Owner to procure equipment or gain physical or contractual control of UFLS equipment in its area as part of the Planning Coordinator's establishment of a UFLS program under PRC-006-SPP_01. Southwestern believes that if this is the intent of the proposed language in section 4.2 of the Applicability Section, in contrast with the language included in draft 3, it reaches beyond the scope of the standard by potentially placing an additional requirement on TOs who do not currently own, operate, or control UFLS equipment. Alternatively, if the intent is for TOs to participate directly, Southwestern does not believe that scenario will result in increased reliability. There are TOs in the SPP region who do not directly serve end-use load and are technically incapable of responding to an UFLS event at the granularity achieved by DP's who are in control of distribution level substations and feeders. Requiring TOs to shed load at the transmission level may result in excessive load loss and a potential overshoot which could lead to a high frequency situation.

SDT General Response	**Several comments refer to the Objectives listed on the comment form. The comment form will be updated before the next release.** **The number, type and location of Under-Frequency Load Shedding (UFLS) equipment will normally be the responsibility of the UFLS entities based on programs established by the Planning Coordinators. UFLS entities may implement an aggregated UFLS program with other UFLS entities. In R1 and R2, the 100 MW limit refers to the aggregated UFLS program, if one exists.** **The SPP UFLS Standard does not specifically say you can aggregate UFLS programs, but it also does not say you cannot aggregate UFLS programs. The intent of the Standard is to allow flexibility on meeting the requirements; i.e. three steps of Underfrequency shedding certain percentages of load at each step, etc.** **Currently under the SPP UFLS Criteria, the Balancing Authority assigns UF relay locations to meet SPP UFLS Criteria. And in some cases, the Balancing Authority is basically aggregating UF programs today. Once this Standard is approved the underfrequency responsibilities will move from Balancing Authority to Registered Entities that supply load to customers. If the Registered Entity wants to continue to let the Balancing Authority provide UF relaying then the Registered Entity can aggregate their UF program. If the Registered entity has a better option, they are free to do that.** **The proposed SPP UFLS also does not specifically say that underfrequency relays need to be installed on Distribution feeders. So by not specifying it, there is an option to install underfrequency relays on a Transmission circuit. That is an option to allow the UFLS entity to design a plan to meet there needs and also meet SPP load shedding requirements.** **The SPP UFLS Standard does have specific requirements that need to be met in order to “arrest declining frequency and assist in recovery of frequency following underfrequency events”. But we wanted to Standard to be flexible to allow UFLS entities different ways to meet these requirements.**

SOUTHWEST POWER POOL
PRC-006-SPP-01
Regional Reliability Standard

Background

The Purpose of the SPP PRC-006-SPP-01 standard is to develop, coordinate and document requirements for automatic under frequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following under frequency events. The NERC PRC-006-1 requires the Planning Coordinator (SPP) to develop a program to meet a set of performance characteristics where there is an underfrequency condition caused by an imbalance between load and generation. The SPP SPCWG along with Powertech labs and the input from numerous SPP members developed this standard to meet these performance requirements.

SPP has had an UFLS requirement for its members for many years. These requirements were documented in the “SPP Criteria”. The performance requirements of the new PRC-006-SPP-01 are very similar to the original SPP Criteria requirements. The primary difference is the Applicability of the new Standard. UFLS entities will be identified by the Planning Coordinator and may include Distribution Providers, Transmission Owners and others. It is foreseen that there will be changes in UF locations, additions and removals of UFR, and aggregated UFLS program. Because of this there will be a multiyear implementation plan.

Summary of Comments

The SPCWG received several comments on Generator Owner participation in this Standard ranging from Applicability to performance requirements. The SPCWG believes that since an underfrequency condition involves both load and generation, Generator Owners and generator requirements have to be included. This also aligns with generator requirements included in the original SPP Criteria; Section 7.3.1.3 d. “The tripping of any generating unit by under-frequency relays or any other protective device during low frequency conditions shall be so coordinated that these units will not be tripped before the three steps of load shedding have been utilized. Should this not be practical due to the operating characteristics of certain units, then these members shall protect the interconnected systems by shedding a block of load equal to the capability of the generating unit that will be tripped and at the frequency which will remove the unit from service.”

The SPCWG received several comments on Attachment 1 “Underfrequency Curve for Requirement 7”. This is a generator operation curve developed by SPCWG to coordinate generator tripping with the dynamic simulation underfrequency results of the “2010 Evaluation and Assessment of Southwest Power Pool (SPP) Under-Frequency Load Shedding Scheme” prepared by Powertech Labs Inc. Adherence to this curve will help avoid aggravating an underfrequency situation by tripping additional generation. The Powertech study also verified that other requirements listed in the SPP UFLS standard adhered to the NERC performance criteria.

The SPCWG received several comments from Registered Entities with large load blocks concerned with meeting the minimum and maximum load relief percentages in the three steps of underfrequency. The number, type and location of Under-Frequency Load Shedding (UFLS) equipment will normally be the responsibility of the UFLS entities based on programs established by the Planning Coordinators. UFLS entities may implement an aggregated UFLS program with other UFLS entities. In R1 and R2, the 100 MW limit refers to the aggregated UFLS program, if one exists.

A lot of comments received by the SPCWG were incorporated into the Standard. The SPCWG would like to express its sincere thanks to the many people who supplied comments, feedback, clarification and direction in the development of this Standard.

Thanks,

SPP UFLS Standard Drafting team

1. **Do you agree that this Standard is ready for Ballot? If not, provide specific suggestions that would make it acceptable to you.**

Organization	Question 1:	Question 1 Comments:
AECC	No	1. Given NERC's BOT approval of PRC-006-1 does the FERC order requiring SPP to develop a regional standard still apply? PRC-006-1 doesn't apply to the Regional Reliability Organization or its equivalent. It appears that the responsibilities for developing the UFLS program are being assigned to the Planning Coordinator and not the RRO. If PRC-006-1 is the guiding document, is there a need for SPP to develop a regional standard? SPP would be involved as a PC and as such would have to develop a program but not a standard. SPP is only the PC for SPP members. Non-SPP members are not subject to SPP PC requirements. Therefore SPP believes a Regional Standard is needed for overall participation. SPP also believes that an UFLS program needs to include Generator Owners (GO) since GO have an essential part in balancing load and generation. 2. Applicability: The drafting team has used the applicability section of PRC-006-1 as the guide for applicability to SPPs standard with the exception of Section 4.3. 4.3 of PRC-006-1 should be added. In addition, as written the SPP standard does not apply to LSEs. LSEs are the only entity under the NERC Functional Model that have load. PRC-007-0 and PRC-009-0 both apply to the LSEs and TOPs. Since this standard will outline the roles and responsibilities under the regional UFLS program, all entities which may have responsibilities under PRC-006, 007, 008, or 009 should be taken into consideration for inclusion. Nothing in PRC-006-1 precludes the inclusion of other entities such as the LSE or TOP. Concerning formatting, AECC's preference for the applicability section is that it be constructed similar to PRC-007-0 instead of PRC-006-1. It is much easier to determine to whom the standard applies. Section 4.2 of the applicability section includes TOs. NERC PRC-006-1 Applicability Section 4.3 is for Requirement R10 for TO's that provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage. Section 4.3 is used for the WECC region and not SPP. Since NERC PRC-006-1 will be the continent wide standard, the SDT felt comfortable with only using the continent wide language. 3. The following comments apply to R1.1: 3a. AECC still opposes the maximums on Steps 1 and 2. Expanding the maximums to 25% and 35% helps AECC's situation but does not necessarily alleviate it. With the 45% maximum in Step 3 AECC still believes that there is no need for upper limits in Steps 1 and 2.

		The maximums on Steps 2 and 3 are the maximum allowed to meet the 3 steps of 10% minimum. 3b. AECC has not opposed the 45% limit in Step 3 in the past but recent examinations of AECC load indicates the possibility of a problem meeting this limit. The problem lies in the cumulative effect of diversity. The SPP PRC-006 Standard is a Planning based standard. 3c. AECC has raised the issue of measuring performance to the standard and continues to believe this will be a principal driver going forward as NERC moves toward more performance based standards. Although the intent is for this standard to be a planning based standard, PRC-009-0 R1 is a good example how the performance of the program will be the determining factor of how well SPPs program is designed. This means that although a UFLS plan is designed to a certain load level it must be flexible enough to handle other load levels that an entity may experience. This is where AECCs situation really comes to light. It is understood that Underfrequency load shedding levels in the SPP footprint does vary for all UFLS entities. SPP uses best practices to determine compliance with NERC UFLS Standard requirements. Based on data supplied by UFLS Entities in the SPP footprint SPP exceeds performance standards. As changes to the SPP footprint occur, future studies will be made to measure performance to verify SPP's UFLS program complies with NERC performance standards. 4. AECC does not oppose reporting the data as outlined in R5 however this data is very sensitive. There should be some guarantee that the data will be secure and used only for the purposes for which it was provided. At a minimum the data should be declared CEII. This should be included in the standard and very clearly instruct that SPP, the PC, or anyone else having assess not use the data for ANY purpose other than meeting the requirements of PRC-006-1. SPP will take this under advisement and review their current practices. 5. The following comments apply to R4: 5a.The bullets should be numbered for easier reference. Bullets provide an "OR" condition, therefore numbering them would cause both bulleted items having to be met to trigger another study. The SDT believes the bullets are appropriate. 5b.What are the performance characteristic changes referred to in the first bullet? is this referring to PRC-006-1 4.7 through 4.7 and SPP R1 and R2? A reference to the specific characteristics is needed.

		Agreed 5c.Is it the intent of the first bullet that a technical assessment be done every time someone makes a change in their program (add a relay, changes a relay setting, etc.) or there is a change in the PRC-006 or SPP standard? Needs clarification. The intent is if there is a changes to the boundaries or standard change (CW or SPP), the PC shall perform a new technical assessment. 6. Comment 4 also applies to R6. 7. R7 states: "... Generator Owner shall verify ..." What does it mean to "verify"? Is this by documentation, testing, or other means? Consider replacing “verify” with “determine”. Verify is more to confirm something as true whereas determine is more about coming to a decision after investigation. The SDT leans more toward the Generator Owner to Verify. 8. Reword 8.1 to say “The Planning Coordinator shall determine if the UFLS program performance is degraded due to the removal of any generation identified in accordance with R7.1.” and make this requirement 7.2 Agreed 9. The following comments apply to the main body of R8: 9a.What is meant by “sufficient technical evidence”? R6 and R7 require the generator to submit and verify its data. Any technical evidence the PC requires should be spelled out in R6 specifically so that there is no question as to what would be sufficient. SDT changed to “technical evidence”. Technical evidence requirement is located in R7.1, where the Generator Owner shall provide to the Planning Coordinator technical evidence demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer’s published equipment ratings. 9b. If the GO is providing the data specified in R6, the need for the PC to make a determination if the data provided is "sufficient technical evidence" is not clear. The GO is on the hook for the data and its quality. If the accuracy of the data is the concern then the PC is not in a better position than the GO in determining if the data is accurate. If the provision of enough data or absence of data is the concern the GO would be in violation of R6 if the data is not provided. If data being unavailable is the concern, one thing the standard could include would be acceptable industry standards that could be used in lieu of actual data. If this is to provide wiggle room for a GO

		in providing data under R6 then this should not be allowed unless it is also extended to the other UFLS Entities under R1 and R2. same as above. 10. AECC does not agree with the concept presented in 8.1.1 based on the following: As the PC studies the UFLS program within SPPs footprint, the PC will determine if the lost of certain generators due to early tripping requires additional load to be shed. If the GO is a UFLS Entity and has the required amount of supplementary Load available, the PC shall notify the GO of Load the entity is required to shed. If the Entity is only a GO or does not have the ability to shed additional load, the PC will work with the neighboring Entities to determine where the load can be shed. The ultimate goal is to balance the system so total collapse does not occur. 10a.It has been stated that the reason for R8.1.1 and R9 is "because of the national standard" implying PRC-006-1. There are no references in PRC-006-0, 006-1, 007-0, 008-0, or 009-0 to a generator owner needing to make arrangements for shedding load. This may have been a suggestion somewhere along the way but it doesn't appear in the standards. PRC-006-0, PRC-007-0, and PRC-009-0 will be retired when PRC-006-1 becomes effective. PRC-008-0 will be retired when PRC-005-2 becomes effective. 10b.The draft versions of the UFLS standard for other regions do not include such requirements. Reference PRC-006-NPCC-1 Requirement R18.3. Reference PRC-006-MRO-01 Requirement R6.1. Reference PRC-006-RFC-01 Requirement R12.1. 10c. R8.1.1 goes beyond the NERC requirements and the requirements being proposed in other regions and should be deleted along with R9 and R6.6. AECC does not disagree that GOs should provide data to be used in the PCs assessment but that is all. The ultimate goal is to balance the system so total collapse does not occur. The PC needs to determine the UFLS performance is not degraded due to the removal of any generation due to early tripping IAW with R7.1. 10d. A "UFLS Entity" has done its part by complying with R1 through R5 and should not be penalized by being required to shed additional load because a generator doesn't meet the requirements of R7 either intentionally or by design. Any generators not meeting the requirements of R7 should be noted in the PCs database and taken into account in the PCs Assessment. If during a PCs assessment a stability issue is identified then the problem should be dealt with locally and by any means available with additional load shedding being the last resort. The

		entire region should not be subjected to "supplementary shedding of load" for a local or isolated problem. SPP has conducted a study to show that a substantial portion of the regions generation can be lost before instability becomes a problem. If the PC conducts its assessment taking into account the premature tripping of a generator and the impact of losing the generator does not create instability then there is no need for supplementary load shedding. If the UFLS program performance is degraded due to the loss of any generation identified IAW R7.1 supplementary load shedding is required. The ultimate goal is to balance the system so total collapse does not occur. The PC will work with both the GO and UFLS Entity to meet UFLS program performance. 10e. By requiring supplementary load shedding the drafting team has created a situation where the UFLS entity could exceed the maximum limits set forth in R1.1. This goes against the grain of the drafting teams concern for shedding too much load and is contradictory to the intent of the limits. If supplementary load shedding is required the PC will work with both the GO and UFLS Entity to meet UFLS program performance. 11. Based on the comments above the main body of R8, R8.1.1, R9, and R6.6 should be deleted. Reference 10c response. 12. If R8 remains the bullets in 8.1.1 should be numbered for easier reference. Same as 5.a 13. R8.1.1: Generator Owners do not have load. Only LSEs have load.
AEP	No	R1 and R2 - intentional time delay of 30 cycles is too long. Total relay and breaker operating time should be at most 27 cycles for a program with ten percent steps spaced .3 Hz apart assuming aggregate inertia (H) is about 4.0. Intentional relay time must allow for relay pickup and breaker operating time. If the time delays are too long, more UFLS stages may be shed than necessary which may lead to high frequency. The SPP Powertech study did study the effect of delay in operation of UFLS relays. The study results indicated the system remains reasonably secure with all UFLS relays adjusted to 30 cycles and breaker times adjusted to 6 cycles. R1 - One concern is making sure the document does not make TO have UFLS to account for non-retail loads that should be covered by another Distribution Provider. Replacing the term "Load" in B. R.1 with "Retail Load" would seem to clarify this for the Transmission Owners. But it might confuse things for some coops who may say their member coops are not retail load.

		The SDT has discussed various terms at considerable length and believe the current term to be appropriate. The definition for the total forecasted peak Load has been added to the latest draft. R 1.1 - Perhaps column 3 and 4 should just say "Minimum accumulated percentage load relief" and "Maximum accumulated percentage load relief". This would avoid giving the impression that a company with a "peak load" of 1000 MW has to shed a minimum of 100 MW at 59.3 Hz, even if their load at the time of the event (perhaps off-peak) is only 500 MW. The intent is for the Entity to determine its amount of load at peak and during the off peak times, the load per step would be reduced. The SDT understands this may not be the case for all steps but the studies show changes to the load is acceptable and the system can survive. If future studies show otherwise, the standard will be changed. R 1.3 - In section 1.3, the 85% undervoltage inhibit upper limit is too high. Perhaps some series of events such as more than one generator tripping off and/or more than one line tripping out, which may be associated with an underfrequency event, may cause voltage in some areas to drop to a little below 85%, at which point some of the UFLS may be disabled just at the time it is needed. The SPP PowerTech study specifically studied the 85% setting and determined to have negligible impact on the SPP system. R3 - Seems like all the islanding ought to take place at the same frequency, not over a range (58.5 - 58.0). Otherwise, it may increase the likely of odd system configurations during a UF event. Perhaps consideration should be given to going with the 58.5 Hz frequency recommended in Criteria 7.3.1.2.c and discussed in 7.8.4.1. The SPP UFLS study, conducted by Powertech, showed that frequency excursions between 58.5 and 58.0 Hz would recover in less than 2 seconds. Therefore, having a 2 second time delay may avoid islanding. R4 - "specified island" not defined. Due to the collection of data in R5, the PC will have all boundaries of islands. R4 - "Occurrence of any of the following situations" should be specific to SPP standard R1 or R2 changes. Any changes to the NERC performance criteria would be addressed within the NERC standard's implementation plan. Also, changes to nonconforming generation compensatory load shedding might be cause for reassessment. Agreed

		R5 - 30 days seems rather quick, maybe 45 should be considered. Current turn around of data is 30 days so the SDT did not make any changes R6.4 – The requirement should be specific to which type of breaker (generator breaker, unit breaker, etc.). Also, the Generator Owner may not be the owner of the breaker. If so, is the GO require to provide the data? The SDT is requesting breaker operating time on the breaker which takes the unit off-line. If the breaker is owned by another Entity, the GO will need to request the information from the breaker owner. R6.6 – This requirement is no longer applicable since the information should be provided under R5 from the UFLS Entity. This requirement might relocated under R5 and point to R9 instead. Standard has been updated to reflect this. R8.1.1 - would be simplified if the first was removed and the second bullet read: "The Planning Coordinator shall notify any other UFLS Entity(s) within the Planning Coordinator Area of Load the entity(s) is required to shed (in addition to that required in accordance with R1 and R2)" This would remove the GO from the communication channels and the PC would coordinate with the UFLS Entity. Entities can have multiple Registration Status; DP, GO, TO etc. If an entity is registered as both a GO and a DP, then the entity is considered a UFLS Entity. The first bullet refers to this type of entity. R9 - This could be read as implement for a real time load shedding event. The requirement should be clarified to indicate that a program is implemented in the Long-term Planning Horizon. Supplementary shedding of Load will be directed by the Planning Coordinator. R9 – This requirement should only be applicable for the UFLS entity. A Generator Owner could also be a UFLS entity. Attachments 1 & 2 – The curves used in the NERC Standards should be utilized as the performance criteria in the Regional Standard. These less restrictive curves in this project will defeat the purpose of coordination between UFLS and generator tripping.

		The Attachments 1 & 2 were developed from the SPP PowerTech study which could require additional supplementary load shedding due to removal of generation identified IAW R7.1. Future SPP PowerTech studies could revise these attachments.
NPPD	No	NPPD will vote negative when the standard PRC-6-SPP-01 is presented for ballot because we have not completed our evaluation of the standard for our Nuclear plant. In order for NPPD's nuclear unit to determine capability to meet this standard will require extensive evaluation of load calculation assumptions for generator frequency and further detailed analysis on turbine protection with no assurance of capability to meet this standard. Evaluation time for the nuclear plant is estimated at 300 hours. Requirement R8 addresses this issue. In addition, NPPD recognizes a risk from the compliance perspective with SPP being our Planning Coordinator and the MRO being our RE. NPPD would prefer to work under a continent-wide standard. SPP is only the PC for SPP members. Non-SPP members are not subject to SPP PC requirements. Therefore SPP believes a Regional Standard is needed for overall participation.
OPPD	No	Respective RE's should be auditing applicable registered entities (Planning Coordinators in this case) to the actual NERC standard and not creating their own. MRO has this philosophy and is moving away from regional standards. . SPP is only the PC for SPP members. Non-SPP members are not subject to SPP PC requirements. Therefore SPP believes a Regional Standard is needed for overall participation. This regional requirement is circumventing the actual NERC requirement in several ways For instance, PRC-006-1 R14 allows UFLS entities or Transmission Owners to provide comments to the Planning Coordinator regarding the UFLS program. If this regional standard was in place, I'm concerned that registered entities will not be allowed to comment on the overall UFLS program that should have been created by the PC instead of a regional requirement."
SPS	Yes	SPS understands the problem with entities that do not have load to interrupt, i.e. Generator Owners who are not part of an integrated utility. Requirement 8 can force the Transmission Owners (TO) and Distribution Providers (DP) to interrupt load because another entity doesn't have load to interrupt, increasing the burden on the customers of those TO's and DP's. Likewise, this standard does not apply to Load-Serving Entities (LSE) who certainly have customers that could be interrupted to reduce load and help stabilize the entire system. It seems to SPS that the burden of possible interruption should be spread across all customers utilizing the Bulk Electric System. This could be accomplished by extending the definition of a UFLS entity to include LSE's. Applicability 4.2 applies to all UFLS entities who are responsible for the ownership, operation, or control of UFLS

		equipment as required by the UFLS program established by the PC. SPS would also like clarification around Requirement 3. Is this requirement intended to apply to all islanding schemes, including out-of-step (OOS) tripping? On the SPS system, delaying all OOS tripping by 2 seconds after the frequency has dropped below 58.5 Hz may prevent isolation of a particular affected area of our system, which could result in the loss of the entire SPS system. Requirement 3 has been revised by adding “underfrequency islanding schemes”. A note has also been added to R3 stating that out-of-step tripping is not part of R3’s islanding scheme.
SWPA	No	Southwestern Power Administration (SPA) believes the drafting team needs to further clarify that this standard will apply directly to entites that currently own, operate, or control UFLS equipment. Leaving entites that currently do not have UFLS equipment, or are currently not accountable for the continent wide NERC standard PRC-006 open to an interpretation by the Planning Coordinator on whether that entity should be held accountable or be forced to install currently non-existent UFLS equipment for this regional standard is ambiguous. It is the intent that all entities within the SPP foot print provide some load shedding to protect the BES from collapsing. The PC thru their studies will make the final determination per PRC-006-1 Make the applicability clearly defined, not open to an interpretation.

Additional Comments:

Organization	Additional Comments:
AECC	The SPCWG is to be commended for the good job they have done in developing this standard. Although I have not always agreed with what has been presented, I do appreciate their hard work. The SDT appreciates the acknowledgment.
SWPA	Southwestern Power Administration (SPA) has concerns that if the Planning Coordinator indicates SPA must install UFLS equipment on its transmission system, that it will be unable to meet the requirements listed in the table for requirement 1.1 since large blocks of load will be interrupted at the transmission level. A more granular load reduction would be accomplished on the subtransmission and distribution level however, Southwestern does not own, operate, or maintain any facilities at this level. It is the intent that all entities within the SPP foot print provide some load shedding to protect the BES from collapsing. The PC thru their studies will make the final determination per PRC-006-1

Organization	Vote	Comments:
Omaha Public Power District	Negative	In general, a regional standard is not necessary to support the actual NERC PRC-00601 Standard. Per the PRC-006-1 Standard, the PC should create the actual UFLS plan. For example, the MRO RE is not creating a regional standard. Also, the regional plan directly circumvents many of the actual requirements of the PRC-006-1 Standard.
SDT Response	**Please refer to the PRC-006-SPP-01 Minority Report.**	
Cleco Corporation	Affirmative	
Nebraska Public Power District	Negative	NPPD has not completed evaluation of this Standard on it's Nuclear Plant and in that light cannot vote affirmative at this time.
SDT Response	**Noted.**	
Oklahoma Gas and Electric Co.	Affirmative	
Arkansas Electric Cooperative Corporation	Negative	Draft 7 does not address AECC's concerns which have been expressed in prior comments.
SDT Response	**Please refer to the PRC-006-SPP-01 Minority Report.**	
City Utilities of Springfield, MO	Affirmative	
East Texas Electric Cooperative, Inc.	Affirmative	
Southwestern Power Administration	Negative	Southwestern feels that giving the Planning Coordinator (PC) the authority to establish what entities require UFLS equipment without any clearly defined methodology or requirements (on the PC) is of great concern to the Agency. This standard (as written) in today's bulk power system will not be applicable to Southwestern. However, by authorizing the Planning Coordinator to decide based on (?? Criteria) what and where new UFLS relays shall be installed and that could then make Southwestern responsible for this standard is enough cause for concern for the Agency to vote against the standard as written.
SDT Response	**The Powertech UFLS study will determine if the current SPP UFLS program is adequate and the study will dictate the need for additional UFLS relays.**	
Lincoln Electric System	Negative	LES recognizes the amount of effort the SPP RE, SPP RTO and the SPP membership has put into the development of this Regional standard, however LES must vote negative on this standard based for the following reasons. (paragraph break) This Regional standard is not needed with the NERC BOT adoption of NERC standard PRC-006-1 on October 18, 2010. LES believes that a UFLS program should cover the entire SPP RTO (or more specifically the Planning Coordinator) footprint, however passing a SPP RE Regional Standard will not accomplish this. In only 2 of the 8 NERC RE Regions do the RE boundaries align with the RTO

		boundaries, thus it makes little sense to develop UFLS programs on a RE footprint basis as is required in the current mandatory and enforceable NERC UFLS standard, PRC-006-0 (version zero). NERC recognized this fact and has assigned the responsibility of developing a UFLS program to the Planning Coordinator, i.e. the SPP RTO, in the new continent-wide NERC standard PRC-006-1. FERC also agrees with this approach as is evident in their NOPR to approve PRC-006-1 filed on October 20, 2011 (Docket No. RM11-20-000). Within Paragraph 46 of this Order FERC states: (paragraph break) Requirement R2.3 allows planning coordinators to "adjust the island boundaries to differ from the Regional Entity area boundaries by mutual consent where necessary" to preserve contiguous island boundaries that better reflect simulations. The Commission agrees that identifying island boundaries based on where they are likely to occur due to system characteristics, as opposed to maintaining rigid Regional Entity area boundaries, should result in more effective UFLS programs. Accordingly, the Commission encourages cooperation among entities to create UFLS programs that set island boundaries based on where separations are expected to occur during an underfrequency event. (paragraph break) As the SPP RE Standard Drafting Team knows, the PRC-006-1 NERC standard essentially requires that the Planning Coordinators (the SPP RTO) develop a UFLS Program for their Planning Coordinator footprint, and that their UFLS Entities (which WOULD include the non SPP RE registered entities) are required to follow that Program. This SPP RE regional standard (which was written for the most part by SPP RTO staff) would be duplicative, confusing and unnecessary based on the fore mentioned facts. Rather than creating another standard to comply with, the SPP RTO and their members (including LES) should work toward creating the SPP RTO's UFLS program, that will incorporate the ideas outlined in the draft SPP RE standards AND meet the requirements written within the NERC standard. This SPP RE Standard does not meet the SPP RTO's NERC obligations to create a UFLS program. It is important for the SPP RE Board to recognize that this proposed SPP RE standard will not apply to the "UFLS entities" outside of the SPP RE footprint, currently in the MRO and SERC regions, but could continue to change as the SPP RTO looks to expand its footprint…. and the SPP RE footprint will remain unchanged. These "UFLS Entities" outside of the SPP RE are not registered in the SPP RE region and are therefore outside of the SPP RE's 'jurisdiction'. It appears that the draft SPP RE UFLS standards is attempting to pull in these non SPP RE UFLS Entities, however this will not be successful unless a change is made to the NERC Compliance Registry. In contrast, per the NERC standard PRC-006-1, non SPP RE entities would be required to follow the SPP RTO UFLS program, because the regional limitation is removed from the standard. (paragraph break) LES looks forward to working with SPP RTO staff in creating the SPP RTO's (i.e. the Planning Coordinator's) NERC required UFLS Program which will be mandatory and enforceable in the entire SPP RTO footprint.
SDT Response	**Please refer to the PRC-006-SPP-01 Minority Report.**	
Grand River Dam Authority	Affirmative	
Southwest Power Pool	Affirmative	

Westar Energy, Inc.	Affirmative	
American Electric Power	Negative	AEP is casting a negative ballot primarily due to the contents of Attachments 1 & 2. These attachments should use the curves as provided in the NERC Standards as the performance criteria in the Regional Standard. Having two sets of curves in the NERC and SPP standards will only cause undue confusion to the industry, without any significant benefit to reliability. While it is true that the generator curves in NERC PRC-006-1 are limited to indicating when generator under- and over-frequency trip settings should be represented in UFLS assessments, these curves are coordinated with NERC draft PRC-024-1 (the generator curves in NERC PRC-006-1 Attachment 1 are the same as PRC-024-1 Attachment 1). NERC PRC-024-1 will require that Generator Owners supply technical justification for any settings within the envelope (no trip zone) of the two curves, same as PRC-006-SPP-1 R7 will require for any settings between its curves. A uniform continent-wide requirement on generator under- and over-frequency tripping really is desirable to avoid confusion. It is also necessary for coordination of generator tripping with continent-wide UFLS performance criteria in the now NERC Board approved NERC PRC-006-1. Nothing is lost if SPP's curves are made the same as draft NERC PRC-024-1. The same non-conforming generator trip settings (perhaps more because NERC Attachment is more restrictive) will still be available to the Planning Coordinator and the PC can still do what it needs to do under SPP R8, including identifying supplementary load shedding, should it find that the UFLS program is degraded. Once NERC PRC-024-1 becomes enforceable, SPP R7, R7.1, and R8 (keep R8.1) can be removed with no change in what a Generator Owner needs to comply with. For R9, we suggest changing the wording so that it is clear that the actionable element of the requirement is that procedures are implemented, rather than requiring that load shedding is to occur. AEP suggests the following suggestion. "The Generator Owner or other UFLS entity(s) shall provide automatic supplementary load shedding capability as required by the Planning Coordinator in accordance with R8.1.1." AEP requests that future drafts use redlining to clearly indicate the changes that have been made since the previous draft. {This comment field does not allow for cut and paste of multiple paragraphs. Please consider modifications to the webpage to allow more functionality.}
SDT Response	**Attachments 1 and 2 were developed from the results of the Powertech study for the SPP footprint for meeting the NERC PRC-006 performance characteristics.**	
Sunflower Electric Power Corporation	Affirmative	
Midwest Energy, Inc.	Negative	1._Requirement R7 related to generators meeting the performance curve data is poorly defined. It would seem that "size matters". Is the applicability to a 700MW unit the same as a 7MW or 0.7MW unit? 2._Requirement R3 makes it clear that the UFLS entity can elect, at is option, to implement an islanding scheme if it desires. However, in the violation severity level table it is indicated that failure to develop an islanding scheme is a severe violation.

		3._The standard is unclear throughout when data must be provided to the Planning Coordinator. In some cases it says data will be provided upon request. In other instances, such as the violation severity table, it suggests that data must be provided at some interval following a compliance audit. Which is it? If there is a recurring obligation to provide data, what is that frequency of data reporting?
SDT Response	**According to R7, if a generator can't meet the performance curves in Attachments 1&2, then it becomes the responsibility of the Planning Coordinator to determine if the UFLS program performance is degraded due to the removal of the generation. Therefore the units will be treated on an individual basis and will not be treated the same regardless of the size of the unit.** **The VSL table entry for R3 wording indicates failure to develop an islanding scheme "per the requirement" (ie., R3) is a severe violation. The intent of the SDT is not to require islanding schemes, they are optional per the Requirement as you point out, but rather to set forth criteria that must be met by islanding schemes if they are employed in order to coordinate with the UFLS scheme. Not adhering to these criteria "per the requirement" creates the violation for those electing to employ an islanding scheme.** **The requirements state when the data must be supplied to the Planning Coordinator (i.e. within 30 calendar days upon request from the Planning Coordinator). The Data Retention section of the Standard specifies how long data should be kept (i.e. evidence necessary to show compliance since the last compliance audit).**	
Green Country Operating Services, LLC	Affirmative	
Yoakum Electric Generating Cooperative, Inc.	Affirmative	
Golden Spread Panhandle Wind Ranch, LLC	Affirmative	
Denver City Energy Associates (Mustang Station)	Affirmative	
Tenaska Gateway Partners Ltd	Negative	Please clarify what is wanted by a Generator in R7; my relay settings were given in R6.
SDT Response	**According to R7.1, the Generator Owner shall provide any <u>technical evidence</u> demonstrating that the unit cannot operate within the specified range <u>without causing equipment damage or violating manufacturer's published equipment ratings</u>. This will require more than just the relay settings from R6.**	
Mid-Kansas Electric Company, LLC	Affirmative	
Edison Mission Marketing & Trading, Inc.	Negative	The term verify is too vague. I would purpose that the term be verified by review of current relay settings.
SDT Response	**The SDT doesn't believe that "verify by review of current relay settings" adds any clarity to the term.**	
Southwestern Public Service Co. (Xcel Energy)	Affirmative	
Coffeyville Municipal Light &	Affirmative	

Power		
The Empire District Electric Company	Affirmative	
Carthage Water & Electric Plant	Affirmative	
Southwest Arkansas Electric Cooperative	Negative	Draft 7 does not address AECC's concerns which have been expressed in prior comments.
SDT Response	**Please refer to the PRC-006-SPP-01 Minority Report.**	
Kansas Electric Power Cooperative, Inc.	Affirmative	
Petit Jean Electric Cooperative	Negative	Draft 7 does not address AECC's concerns which have been expressed in prior comments.
SDT Response	**Please refer to the PRC-006-SPP-01 Minority Report.**	
Northeast Texas Electric Cooperative, Inc.	Affirmative	
City of Malden – Board of Public Works	Negative	
Poplar Bluff	Negative	1) R1.1 and R2.2 can be misinterpreted as specifying the amount of load to be shed both on peak and off peak. 2) M1 and M2 do not follow the Reliability Standards Development Procedure by adequately identifying to whom the measure applies. 3) The combination of Requirements with Measures does not follow the Template Guide for New Standards.
SDT Response	**The load to be shed is described as the "load relief as percentage of forecasted <u>peak</u> Load".** **M1 and M2 refer to "UFLS entities" which is defined in the Applicability section of the Standard.** **The SPP Standard Drafting Team was encouraged by NERC to convert PRC-006-SPP-01 over to this new results-based format.**	
Golden Spread Electric Cooperative, Inc.	Affirmative	
Oklahoma Municipal Power Authority	Affirmative	
City Water & Light – Jonesboro, Arkansas	Affirmative	
Carroll Electric Cooperative	Negative	
KCPL – Greater Missouri Operations	Negative	Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company, both subsidiaries of Great Plains Energy Incorporated (collectively, "KCP&L" or the "Company"), respectfully submit these comments in response to the proposed SPP Regional Standard, PRC-006-SPP-01 Draft 7 issued September 30, 2011. SPP's consideration of these comments

		is appreciated. General Comments: 1. It is difficult to determine what may or may not be part of the comments contained in the grey boxes and what may be intended as part of the Regional Standard. Recommend SPP Standard Drafting Team (SDT) consider removing the grey boxes and place the important content in the requirements and/or the measures and remove the informational content in the grey boxes. Specific Comments: 1. **Requirement R1** Requirement 1.2 specifies a UFLS time delay of no more than 30 cycles. It is also important for UFLS relays to ride through systems under clearing of system fault conditions. Recommend the SPP SDT consider what the minimum time delay should be to help to ensure UFLS relays do not shed load while the power system responds to clearing of system faults. 2. **Requirement R3** Requirement R3 does not seem to consider the potential change in energy to the SPP region under the election of Registered Entities to implement islanding schemes after the initial steps of UFLS have been executed. For example, an island that is created may contain 100 MW of load and 150 MW of generation. That is a loss of 50 MW to the UFLS effort. Multiplying this effect across the SPP region for Registered Entities electing to implement island schemes could result in additional regional imbalance of load and generation. As the proposed SPP Regional Standard alludes, it is important to provide a delay between the execution of the UFLS actions to before implementing island schemes. Two seconds delay may be too short a delay to allow the system to settle down before additional configuration actions occur. Recommend the SPP SDT consider a longer minimum time delay to allow sufficient time for the system to settle down before allowing further changes. 3. **Requirement R4** Requirement R4 is regarding the Planning Coordinator performing technical assessments regarding changes that may have an effect on UFLS performance. Recommend the SPP SDT consider adding a bullet to include technical considerations after analysis of an actual UFLS event which may yield useful observations and result in the need for a technical assessment of the observations. 4. **Requirement 8.1.1** The second bulleted item in requirement 8.1.1 stipulates that for any Generator Owner (GO) that does not meet the UFLS tripping requirements of the proposed standard and it has been

		determined from analysis that the UFLS program is degraded due to the loss of the generation and the GO does not have the required supplementary load to offset the generation loss, the supplementary load must be borne by the other Registered Entities in the Planning Coordinator area. It is not acceptable to impose additional customer loss on other Registered Entities because of the failure of a Generator Owner in meeting these requirements. Recommend the SPP SDT consider modifying this requirement to require those Generator Owners to make the necessary facility adjustments to meet the proposed tripping requirements or to enter into agreements with other Registered Entities to provide the necessary supplemental load reductions. In addition, the accumulative impact of generators that do not meet the tripping requirements may be problematic. Requirement 8.1 is not clear enough to indicate the analysis by the Planning Coordinator is accumulative of all generators identified from R7. Recommend the SPP to modify R8.1 to indicate the analysis is performed under the accumulative impact of all generators identified by R7. 5. **Section 1.2, Data Retention** There is no data retention specified for Requirements R8 or R9. 6. **Violation Severity Levels – R3** Recommend the SPP SDT reconsider the VSL for R3. There are many elements regarding the implementation of an islanding scheme. A Registered Entity may implement an island scheme but fail to implement the correct time delay, or may implement the island scheme above 58.5 Hz. In addition, the VSL descriptions should clearly indicate for those Registered Entities that have elected to implement an islanding scheme(s)
SDT Response	**The grey boxes are informational and are intended to provide explanations on the requirements. The grey boxes will be removed before the Standard is approved by NERC and FERC. The SDT was encouraged by NERC to convert the Standard over to this results-based approach.** **The SDT believes that a time delay on initiation of islanding for frequencies slightly below the third step of load shedding is necessary to allow time for system recovery and to accommodate some frequency to overshoot. The SPP UFLS study, conducted by Powertech, showed that frequency excursions between 58.5 Hz and 58.0 Hz would recover in less than 2 seconds. Therefore, having a 2 second time delay may avoid islanding. There is no minimum time delay for frequencies below 58.0 Hz.** **NERC PRC-006-1 R12 requires the Planning Coordinator to conduct a UFLS design assessment to consider any identified deficiencies from an event assessment.** **Please refer to the PRC-006-SPP-01 Minority Report for the SDT's response to the question about R8.1.1.**	
Piggott Light & Water	Negative	
Tri-County Electric Cooperative	Affirmative	
Kansas City Power & Light	Negative	

Company		
Pablo Ruiz (Charles River Associates)	Affirmative	
Dan Hartman (NW Kansas Regional Energy Collaborative)	Affirmative	
Heidt Melson	Affirmative	
Rick Bartlett – (Independence Power & Light)	Affirmative	

Southwest Power Pool

PRC-006-SPP-01 Compared to FERC Order 672 Criteria

In FERC Order No. 672, the Commission identified criteria it uses to analyze proposed reliability standards to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these criteria and explains how the proposed regional reliability standard PRC-006-SPP-01 meets or exceeds the 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 Cybersecurity protection.

PRC-006-SPP-01 is designed to ensure that automatic Underfrequency Load Shedding (UFLS) protection schemes designed by the Planning Coordinator and implemented by applicable Distribution Providers and Transmission Owners in the SPP region are coordinated to effectively mitigate the consequences of an underfrequency event.

2. **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.

PRC-006-SPP-01 is applicable to Planning Coordinators, UFLS entities, and Generator Owners in the SPP RE region. The term "UFLS entities" in NERC standard PRC-006-1 refers to all entities that are responsible for the ownership, operation, or control of automatic UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include Distribution Providers and Transmission Owners.

3. **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.

The PRC-006-SPP-01 Minority Report, prepared by the SPP UFLS standard drafting team (SDT), presents an overview of the issues identified in comments submitted in consideration of the proposed standard. All comments and concerns were addressed using processes in the SPP RE Standards Development Process Manual. This manual defines the fair and open process for adoption, approval, revision, reaffirmation, and deletion of an SPP regional reliability standard. Standards provide for the reliable regional and sub-regional planning and operation of the Bulk Power System, consistent with Good Utility Practice within SPP RE's geographical footprint.

4. **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.

PRC-006-SPP-01 adds specificity for development and implementation of regional UFLS schemes that is not contained in the NERC Automatic UFLS standard, PRC-006-1. The requirements in PRC-006-SPP-01 were developed by SDT members who collectively have the technical expertise and experience to develop a technically sound standard. The technical basis for PRC-006-SPP-01 was vetted through industry technical experts through five comment periods and two ballots.

5. **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.

PRC-006-SPP-01establishes clear and unambiguous requirements for all applicable entities:

Requirement 1 requires each UFLS entity that has a total forecasted peak Load greater than or equal to 100 MW to develop and implement an automatic UFLS program according to the Planning Coordinator specifications.

Requirement 2 requires each UFLS entity that has a total forecasted peak Load less than 100 MW to develop and implement an automatic UFLS program according to the Planning Coordinator specifications.

Requirement 3 requires each UFLS entity electing to use underfrequency islanding schemes to design those islanding schemes to operate after all three steps of UFLS have been exhausted and the frequency continues to fall to 58.5 Hz or below. For islanding schemes designed to operate at or between 58.5 Hz and 58.0 Hz, the minimum time delay shall be 2 seconds. For islanding schemes designed to operate below 58.0 Hz, no time delay is required.

Requirement 4 requires the Planning Coordinator to perform and document a UFLS technical assessment within one year after a performance characteristic change to PRC-006 or changes to the boundaries of a specified island are identified.

Requirement 5 requires each UFLS entity to maintain and submit the specified UFLS data to the Planning Coordinator within 30 calendar days upon request from the Planning Coordinator.

Requirement 6 requires each Generator owner to maintain and submit the specified data to the Planning Coordinator within 30 calendar days upon request from the Planning Coordinator.

Requirement 7 requires each Generator Owner to verify that their generating unit will not trip above the specified Generator underfrequency curve and below the specified Generator overfrequency curve as a result of the unit frequency protective relay settings.

Requirement 8 requires the Planning Coordinator to determine if the Generator Owner has provided technical evidence demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings.

Requirement 9 requires the Generator Owner or other UFLS entity to implement supplementary shedding of Load required by the Planning Coordinator.

6. 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.

PRC-006-SPP-01 includes both Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement. The ranges of penalties for violations will be based on the applicable VRFs and VSLs and administered based on the sanctions table and supporting penalty determination process described in the FERC-approved NERC Sanction Guidelines.[1]

The SPP UFLS SDT developed the VSLs and VRFs proposed for assignment to PRC-006-SPP-01 in accordance with applicable NERC and FERC guidance. (See *VRF and VSL Justification_PRC-006-SPP-01.docx* for additional discussion regarding the assigned VRFs and VSLs.)

7. A proposed reliability standard 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.

Each requirement in PRC-006-SPP-01 has an associated measure of compliance that will assist enforcement authorities in enforcing the standard in a consistent and non-preferential manner.

8. Proposed reliability standards should achieve a reliability goal effectively and efficiently - but does 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.

[1] NERC Rules of Procedure Appendix 4B

PRC-006-SPP-01 helps the industry achieve the stated reliability goal effectively and efficiently. The proposed standard sets minimum automatic UFLS design requirements which are similar to the design requirements in the current SPP Criteria on UFLS. PRC-006-SPP-01 is based on a planning peak load forecast, while the SPP Criteria is based on an operations viewpoint that the three steps of the UFLS program had to be met “at any given time.”

9. 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 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO’s Reliability Standard development process based on the least effective North American practice — the so-called “lowest common denominator” — if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

The methods in PRC-006-SPP-01 do not employ a “lowest common denominator” approach. PRC-006-SPP-01 was designed to be consistent with the NERC automatic UFLS standard, while adding specificity not contained in PRC-006-1, for the development, coordination, implementation, and analysis of UFLS schemes in the SPP region.

10. 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 cost for smaller entities to implement was considered during PRC-006-SPP-01 development. NERC standard PRC-006-1 requires the Planning Coordinator to identify which entities will participate in its UFLS scheme, including the number of steps and percent load an entity will shed. The SPP UFLS SDT recognized that UFLS entities with a load of less than 100 MW may have difficulty in implementing more than one UFLS step and in meeting a tight tolerance.

Accordingly, Requirement 2 states that such entities shall not be required to have more than one UFLS step. This should limit additional cost requirements for these smaller entities to comply with the standard, but with minimal consequence to operating system reliability.

11. 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.*

PRC-006-SPP-01 was designed on a regional basis to work in conjunction with the NERC UFLS standard to effectively mitigate the consequences of an underfrequency event, while accommodating differences in system transmission and distribution topology within the SPP RE footprint due to historical design criteria, makeup of load demands, and generation resources.

12. 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.

Design and implementation of UFLS protection schemes, as required by PRC-006-SPP-01, will not cause any undue negative effects on competition or operational restrictions or limitations to the grid.

13. 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.

The implementation time for PRC-006-SPP-01 is considered reasonable, with the standard becoming fully effective three years after the first day of the first calendar quarter following regulatory approval.

Requirement 1 shall become effective 3 years after the first day of the first quarter following regulatory approval. This is needed to allow time for any necessary changes to be made to the existing UFLS schemes in the SPP Region.

Requirement 2 shall become effective 3 years after the first day of the first quarter following regulatory approval. This is needed to allow time for any necessary changes to be made to the existing UFLS schemes in the SPP Region.

Requirement 3 shall become effective 3 years after the first day of the first quarter following regulatory approval. This is needed to allow time for any necessary changes to be made to the existing UFLS islanding schemes in the SPP Region.

Requirement 4 shall become effective 1 year after the first day of the first quarter following regulatory approval. This is needed to allow time for the Planning Coordinator to perform a UFLS technical assessment, if needed.

Requirements 5 and 6 shall become effective 1 year after the first day of the first quarter following regulatory approval. This is needed to allow time for the Generator Owners and UFLS entities to gather and submit the data that is requested by the Planning Coordinator.

Requirement 7 shall become effective 3 years after the first day of the first quarter following regulatory approval. This is needed to allow time for any necessary changes to be made to the generators in the SPP Region.

Requirement 8 shall become effective 3 years after the first day of the first quarter following regulatory approval. This is needed to allow time for the Planning Coordinator to receive the generator data and to determine if the UFLS program performance is degraded due to the removal of the generation.

Requirement 9 shall become effective 3 years after the first day of the first quarter following regulatory approval. This is needed to allow time for the Planning Coordinator to determine if the UFLS program performance is degraded due to the removal of the generation and then to assign the responsibility of the supplemental load shed.

14. 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.*

SPP develops regional reliability standards in accordance with the SPP RE Standards Development Process Manual, which is Exhibit C of SPP's Regional Delegation Agreement with NERC. The development process is open to any person or entity with a direct and material interest in the bulk power system. SPP considers the comments of all stakeholders. For an SPP regional reliability standard to be submitted to NERC, it must first be approved by a stakeholder vote and the SPP RE Trustees.

PRC-006-SPP-01 was developed and approved by industry stakeholders using the SPP RE Standards Development Process, and was approved by the SPP RE Trustees on July 30, 2012 for submission to NERC.

15. 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.

SPP developed PRC-006-SPP-01 to address the need for regional requirements for automatic UFLS protection. The proposed regional reliability standard establishes requirements for the design, coordination, implementation, and analysis of UFLS schemes in the SPP region. No environmental, social, or other goals are reflected or considered in this standard.

16. Proposed reliability standard 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.

The proposed PRC-006-SPP-01 Regional Reliability Standard does not conflict with any other prior FERC Rules or Orders and adequately addresses the directives identified in FERC Order No. 693.

17. **Proposed reliability standards must not have a regional difference necessary to maintain reliability.**

Order No. 672 at P 291. A regional difference from a continent-wide Reliability Standard must either be (1) more stringent than the continent-wide Reliability Standard including a regional difference that addresses matters the continent-wide Reliability Standard does not, or (2) a Regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.

The existing NERC continent-wide standard, PRC-006-1 applies only to Planning Coordinators, Transmission Owners, and Distribution Providers. The proposed SPP standard, PRC-006-SPP-01, adds specificity not contained in the NERC UFLS standard for UFLS schemes in the SPP RE Region. Specifically, it is designed to work in conjunction with the NERC standard to effectively mitigate the consequences of an underfrequency event, while accommodating differences in system transmission and distribution topology within the SPP RE footprint due to historical design criteria, makeup of load demands, and generation resources.

Southwest Power Pool

Implementation Plan for SPP Underfrequency Load Shedding, PRC-006-SPP-01

Prerequisite Approvals

SPP Regional Entity Trustees

Proposed Effective Date

Requirements R4, R5, and R6 shall become effective the first day of the first calendar quarter one year after regulatory approval. The one year phase in for compliance is needed for the Planning Coordinator to perform the studies necessary to assess the effectiveness of the UFLS program.

The remaining requirements shall become effective the first day of the first calendar quarter three years after regulatory approval. The additional two year phase in for compliance is needed for any necessary changes to be made to the existing UFLS schemes.

Applicability

The entities listed in the Applicability section will be held responsible for their requirements according to the effective dates listed above.

Field Testing

None

Other Considerations

UFLS entities may implement an aggregated UFLS program with other UFLS entities. In R1 and R2, the 100 MW limit refers to the aggregated UFLS program, if one exists.

PRC-006-SPP-01
Minority Report

Significant Issue #1

Regional Standard vs UFLS Program

Minority Position: A Regional Standard is not needed now that NERC has approved PRC-006. PRC-006 requires the Planning Coordinator to implement a UFLS program, not a Regional Standard.

SPP UFLS SDT Position: NERC PRC-006 is not applicable to Generator Owners. The only way to enforce the Generator Owners' participation in the UFLS program is to create a Regional Standard. The SPP UFLS SDT believes that the UFLS program needs to include Generator Owners since they have an essential part in balancing load and generation. PRC-024-1 is a NERC standard under development that will ensure that generating units remain connected during frequency excursions and ensure expected generating unit performance during frequency excursions is communicated to the RC, PC, TOP, and TP for accurate system modeling.

The Regional Standard approach would require all SPP RE registered entities in the SPP footprint to be held applicable to the SPP Regional Standard; this would include all NERC Registered Entities in the SPP Region. With only the NERC PRC-006 program approach, only those entities for which the SPP RTO is the Planning Coordinator would be held accountable to the UFLS program. Non-SPP members that are in the SPP RE footprint would not be held accountable to the UFLS program and thus would be required to develop their own or have another Planning Coordinator include them in their program.

If SPP, as the Planning Coordinator, is responsible for the reliability of the SPP footprint, then SPP needs the authority of a Regional Standard to fulfill its responsibility.

Significant Issue #2

Waiver Request

Minority Position: The SPP Criteria currently allows SPP members to request a waiver from meeting the UFLS steps. Why aren't waivers allowed in the Regional Standard?

SPP UFLS SDT Position: The Regional Standard was written, as directed, to eliminate the need for waivers.

The SPP Criteria currently states that load that the member will shed is the "one-minute average of the member's load prior to the first underfrequency relay action taken at 59.3 Hz." This load shed “at any given time” approach allowed SPP to accept waivers due to the constant changes in load.

The Regional Standard was written as a planning standard, based on the shedding of each member’s forecasted peak load. Load shedding based on a Planning Standard eliminates load variations proposed in the original SPP Criteria where waivers were needed to meet the percentage of load shedding per step. In the Criteria members could dynamically arm and disarm UFLS relays to achieve the required load shedding totals; dynamic arming and disarming should not be necessary for a Planning Standard.

Significant Issue #3

Generator Owners

Minority Position: Why are TO’s and DP’s required to shed some of their load when Generator Owners, that don’t have their own load to shed, can’t meet the curves in Attachments 1 and 2?

SPP UFLS SDT Position: This approach was the position developed to represent the best balance between competing entities while ensuring an adequate degree of reliability is achieved.

The Planning Coordinator will determine whether the UFLS program is degraded due to early removal of generation and will decide if supplemental load shedding is required to maintain reliability.

The original SPP Criteria required generators that tripped off-line before UFLS Steps were completed to supplement loss of generation with additional load shedding. The original Criteria stated that if a generator tripped before the three steps of load shedding, “then these members shall protect the interconnected systems by shedding a block of load equal to the capability of the generating unit that will be tripped and at the frequency which will remove the unit from service.” Since some Generator Owners do not have load, the PC shall determine if additional load shed is need and will determine if another entity need to shed additional load.

Introduction

1. **Title:** Southwest Power Pool (SPP) Automatic Underfrequency Load Shedding

2. **Number:** PRC-006-SPP-01

3. **Purpose:** To develop, coordinate and document 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 Coordinator

   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. Generator Owners

5. **Effective Date:** Requirements R4, R5, and R6 shall become effective the first day of the first calendar quarter one year after regulatory approval.

   The remaining requirements shall become effective the first day of the first calendar quarter three years after regulatory approval.

6. **Basis for Standard Development:** UFLS entity's planning data for the upcoming calendar year.

UFLS program performance will be measured based on the entity's planning values and not the one-minute average of the entity's load prior to the first underfrequency relay action. This has changed from the current SPP Criteria.

Requirements and Measures

R1. Each UFLS entity that has a total forecasted peak Load greater than or equal to 100 MW shall develop and implement an automatic UFLS program that meets the following requirements: [VRF: High][Time Horizon: Long-term Planning]

1.1. A minimum of 10% shall be shed at each UFLS step in accordance with the table below.

(1) UFLS Step	(2) Frequency (hertz)	(3) Minimum accumulated load relief as percentage of forecasted peak Load (%)	(4) Maximum accumulated load relief as percentage of forecasted peak Load (%)
1	59.3	10	25
2	59.0	20	35
3	58.7	30	45

1.2. The intentional relay time delay for UFLS shall be less than or equal to 30 cycles.

1.3. Undervoltage inhibit setting shall be less than or equal to 85 percent of nominal voltage.

M1. Each UFLS entity shall have evidence such as reports, program plans, or other documentation of its UFLS program that demonstrates it meets requirement R1 Parts 1.1 through 1.3.

The current SPP UFLS program includes three separate UFLS steps with a minimum load shedding percentage of 10%, 20%, and 30%, cumulatively, for each of the three steps. These have remained unchanged from the SPP Criteria. The SDT believed that it was reasonable to increase the maximum load shedding percentages in steps 1 and 2. The maximum load shedding percentages in steps 1 and 2 were increased from 15% and 30%, respectively, to 25% and 35%, allowing more flexibility for those steps.

Total forecasted peak Load is the projected planning value of an entity's end-use customers' coincident system peak load for the upcoming calendar year.

R2. Each UFLS entity that has a total forecasted peak Load less than 100 MW shall develop and implement an automatic UFLS program that meets the following requirements: [VRF: Medium][Time Horizon: Long-term Planning]

2.1. A minimum of one UFLS step with the frequency set point as assigned by the Planning Coordinator.

2.2. The minimum accumulated Load relief shall be at least 30% of the forecasted peak Load.

2.3. The intentional relay time delay for UFLS shall be less than or equal to 30 cycles.

2.4. Undervoltage inhibit setting shall be less than or equal to 85 percent of nominal voltage.

M2. Each UFLS entity shall have evidence such as reports, program plans, or other documentation of its UFLS program that demonstrates it meets requirement R2 Parts 2.1 through 2.4.

The SDT realized that some small UFLS entities may experience difficulty in achieving more than one UFLS step due to a smaller arrangement of loads and meeting the tolerances set forth in the load shedding table of R1.1. The basis for selecting 100 MW as the threshold comes from the use of this same value in other regional UFLS standards and a reasonable judgment that the total forecasted load served by most smaller electric utilities is less than 100 MW. R2 was structured to accommodate these small entities and its inclusion within this standard indicates the importance of having all entities participate in the UFLS program.

R3. Each UFLS entity electing to use underfrequency islanding schemes shall design those islanding schemes to operate after all 3 steps of UFLS have been exhausted and the frequency continues to fall to 58.5 Hz or below. For islanding schemes designed to operate at or between 58.5 Hz and 58.0 Hz, the minimum time delay shall be 2 seconds. For islanding schemes designed to operate below 58.0 Hz, no time delay is required. [VRF: Lower][Time Horizon: Long-term Planning]

M3. Each UFLS entity electing to use islanding schemes shall have evidence such as reports, program plans, or other documentation of its UFLS program that demonstrates it meets requirement R3.

UFLS entities may elect to implement schemes following operation of all three underfrequency steps should the frequency continue to decay. The SDT believes that a time delay on initiation of islanding for frequencies slightly below the third step of load shedding is necessary to allow time for system recovery and to accommodate some frequency overshoot. The SPP UFLS study, conducted by Powertech, showed that frequency excursions between 58.5 and 58.0 Hz would recover in less than 2 seconds. Therefore, having a 2 second time delay may avoid islanding.

This Requirement does not include Out-of-Step trip relaying designed to isolate portions of the power grid for unstable power swings.

R4. The Planning Coordinator shall perform and document a UFLS technical assessment within one year after the occurrence of any of the following situations: [VRF: Medium][Time Horizon: Long-term Planning]

- Performance characteristic changes to PRC-006 or the SPP UFLS standard.
- Changes to the boundaries of a specified island are identified.

M4. The Planning Coordinator shall have evidence that it performed a technical assessment per requirement R4.

Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS is required by NERC PRC-006-0 R1.3 to be conducted periodically (at least every five years or required by changes in system conditions). The purpose of the SPP UFLS requirement R4 is to expand upon NERC PRC-006-0 R1.3. "Changes in system conditions" includes performance characteristic changes in PRC-006 or this SPP UFLS document. This also includes changes to the boundaries of a specified island, for example when Nebraska was brought into the SPP specified island. The SDT believes after such changes it is imperative to perform a new assessment to ensure UFLS program effectiveness.

R5. Each UFLS entity shall maintain and submit the following UFLS data based on the forecasted peak Load to the Planning Coordinator within (30) calendar days upon request from the Planning Coordinator: [VRF: Lower][Time Horizon: Long-term Planning]

5.1. Location of installed UFLS equipment

5.2. Trip frequency(s) for each location

5.3. Total relay operating time of each location (time required for the relay to reliably sense the frequency + intentional delay time (if any))

5.4. Breaker operating time (nameplate) of each location

5.5. Percentage and/or MW of bus load to be shed at the location

5.6. Total amount of load shed by each trip frequency and the total forecasted peak Load

5.7. Tie tripping schemes and the frequency and time delay at which they operate

5.8. Islanding schemes and the frequency and time delay at which they operate

M5. Each UFLS entity shall have evidence that the information was supplied to the Planning Coordinator per requirement R5.

The NERC standard requires that; “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.” The information requested in R5 is the data required by the Planning Coordinator to model the UFLS program and maintain compliance to the NERC standard.

R6. Each Generator Owner shall maintain and submit the following data to the Planning Coordinator within (30) calendar days upon request from the Planning Coordinator: [VRF: Lower][Time Horizon: Long-term Planning]

6.1. Location of underfrequency and overfrequency equipment

6.2. Trip frequency(s) for each location

6.3. Total relay operating time of each location (time required for the relay to reliably sense the frequency + intentional delay time (if any))

6.4. Breaker operating time (nameplate) of each location

6.5. MW of generation shed at each location

M6. Each Generator Owner shall have evidence that the information was supplied to the Planning Coordinator per requirement R6.

The SDT believes this generator data is needed by the Planning Coordinator for the following reasons:
1.) better modeling for UFLS technical assessments,
2.) performing routine UFLS studies, and
3.) post-event analysis.

This data will enable the Planning Coordinator to evaluate whether the generator can meet the R7 requirement and determine if additional load shedding is required on the part of the UFLS entities.

R7. Each Generator Owner shall verify that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2 as a result of the unit(s) frequency protective relay settings. [VRF: Medium][Time Horizon: Long-term Planning]

7.1. For generating units with operating characteristics that limit the unit's ability to perform in accordance with R7, the Generator Owner shall provide to the Planning Coordinator technical evidence demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings.

M7. Each Generator Owner shall have evidence that it complies with R7 or that the information was supplied to the Planning Coordinator, if appropriate, as required in R7.1.

In order to effectively study and evaluate the performance of the UFLS system the generator relay protection trip values must be known. The ultimate goal is to balance the generation and load so that a total collapse does not occur. Therefore, the generator trip values are critical to evaluating the performance of the UFLS system. With this information the system can then be studied.

R8. The Planning Coordinator shall determine if the Generator Owner has provided technical evidence demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings. [VRF: Medium][Time Horizon: Long-term Planning]

8.1. The Planning Coordinator shall determine if the UFLS program performance is degraded due to the removal of any generation identified in accordance with R7.1 and verified in accordance with R8.

8.1.1. If the Planning Coordinator determines the UFLS program is degraded in accordance with R8.1 and that supplementary load shedding is, therefore, required, the Planning Coordinator shall notify the Generator Owner or UFLS entity(s) in accordance with the following:

- Where the Generator Owner is a UFLS Entity and has the required amount of supplementary Load available, the Planning Coordinator shall notify the Generator Owner of Load the entity is required to shed (in addition to that required in accordance with R1 and R2)

- Where the Generator Owner is not a UFLS Entity, or does not have the required supplementary Load available for shedding, the Planning Coordinator shall notify any other UFLS Entity(s) within the Planning Coordinator Area of Load the entity(s) is required to shed (in addition to that required in accordance with R1 and R2)

M8. The Planning Coordinator shall have evidence that it complies with the requirements in R8.

The Planning Coordinator is required to verify the Generator Owner's technical justification for not being able to operate throughout the Attachment 1 and 2 curves and to review the consequences to the UFLS program performance for the loss of that additional generation after the initiation of an under frequency event. It also provides a mechanism for the Planning Coordinator to resolve the detrimental effects of the loss of this additional generation if it determines that the performance of the UFLS program is degraded.

R9. The Generator Owner or other UFLS entity(s) shall implement supplementary shedding of Load required by the Planning Coordinator in accordance with R8.1.1. [VRF: Medium][Time Horizon: Long-term Planning]

M9. The Generator Owner or other UFLS entity shall have evidence that it complies with the requirements in R9.

The SDT's decision to include R9 is to prevent blackouts caused by early removal of generating units from the system. In a real time load shedding event, if the UFLS is degraded in accordance with R8.1.1, removal of units will make the system condition worse. This is the main reason for the supplementary shedding of loads to compromise the loss of generation. This action is critical to bring back the unstable system to stable.

Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

SPP Regional Entity
SERC (for Planning Coordinator only)

1.2. Data Retention

The Planning Coordinator and each UFLS entity and Generator Owner shall keep data or dated evidence to show compliance as identified below unless directed by SPP Regional Entity to retain specific evidence for a longer period of time as part of an investigation:

- Each UFLS entity shall retain the current evidence of Requirements R1 or R2, and R3, Measures M1 or M2, and M3, as well as any evidence necessary to show compliance since the last compliance audit.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator since the last compliance audit in accordance with Requirement R5, Measure M5.
- The Planning Coordinator shall retain the current evidence of Requirement R4, Measure M4 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Generator Owner shall retain evidence of UFLS data transmittal to the Planning Coordinator since the last compliance audit in accordance with Requirement R6, Measure M6.
- Each Generator Owner shall retain evidence of Requirements R7, Measures M7 as well as any evidence necessary to show compliance since the last compliance audit.

If the Planning Coordinator, UFLS entity or Generator Owner 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.

1.3. Compliance Monitoring and Assessment Process

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

1.4. Additional Compliance Information

UFLS entities may implement an aggregated UFLS program with other UFLS entities. In R1 and R2, the 100 MW limit refers to the aggregated UFLS program, if one exists.

2. Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Long-Term Planning	High	N/A	UFLS entity developed a program, but failed to meet any one (1) of the following 5 requirements: Part 1.1 (Step1-3) Part 1.2 Part 1.3	UFLS entity developed a program, but failed to meet any two (2) of the following 5 requirements: Part 1.1 (Step1-3) Part 1.2 Part 1.3	UFLS entity developed a program, but failed to meet three (3) or more of the following 5 requirements: Part 1.1 (Step1-3) Part 1.2 Part 1.3 OR Failed to develop a UFLS program
R2	Long-Term Planning	Medium	UFLS entity developed a program, but failed to meet one (1) of the requirements in Parts 2.1 through 2.4	UFLS entity developed a program, but failed to meet two (2) of the requirements in Parts 2.1 through 2.4	UFLS entity developed a program, but failed to meet three (3) of the requirements in parts 2.1 through 2.4	UFLS entity developed a program, but failed to meet all four (4) of the requirements in Parts 2.1 through 2.4 OR Failed to develop a UFLS program

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R3	Long-Term Planning	Lower	N/A	N/A	N/A	UFLS entity failed to develop an islanding scheme per the requirement
R4	Long-Term Planning	Medium	The Planning Coordinator performed a technical assessment within five years and three months or within one year and three months after one of the situations listed in R4	The Planning Coordinator performed a technical assessment within five years and six months or within one year and six months after one of the situations listed in R4	The Planning Coordinator performed a technical assessment within five years and nine months or within one year and nine months after one of the situations listed in R4	The Planning Coordinator performed a technical assessment within six years or within two years after one of the situations listed in R4 OR The Planning Coordinator failed to perform a technical assessment
R5	Long-Term Planning	Lower	UFLS entity provided required data more than 30 calendar days and up to and including 45 calendar days following the request	UFLS entity provided required data more than 45 calendar days and up to and including 60 calendar days following the request OR UFLS entity did not provide one piece of information listed in R5 (e.g., 5.1.)	UFLS entity provided required data more than 60 calendar days and up to and including 75 calendar days following the request OR UFLS entity did not provide two pieces of information listed in R5	UFLS entity provided required data more than 75 calendar days following the request OR UFLS entity did not provide required data after the request was made OR

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
					(e.g., 5.1. and 5.2.)	UFLS entity did not provide three or more pieces of information listed in R5 (e.g., 5.1. and 5.2. and 5.3.)
R6	Long-Term Planning	Lower	Generator Owner provided required data more than 30 calendar days and up to and including 45 calendar days following the request	Generator Owner provided required data more than 45 calendar days and up to and including 60 calendar days following the request OR Generator Owner did not provide one piece of information listed in R6 (e.g., 6.1.)	Generator Owner provided required data more than 60 calendar days and up to and including 75 calendar days following the request OR Generator Owner did not provide two pieces of information listed in R6 (e.g., 6.1. and 6.2.)	Generator Owner provided required data more than 75 calendar days following the request OR Generator Owner did not provide required data after the request was made OR Generator Owner did not provide three or more pieces of information listed in R6 (e.g., 6.1. and 6.2. and 6.3.)

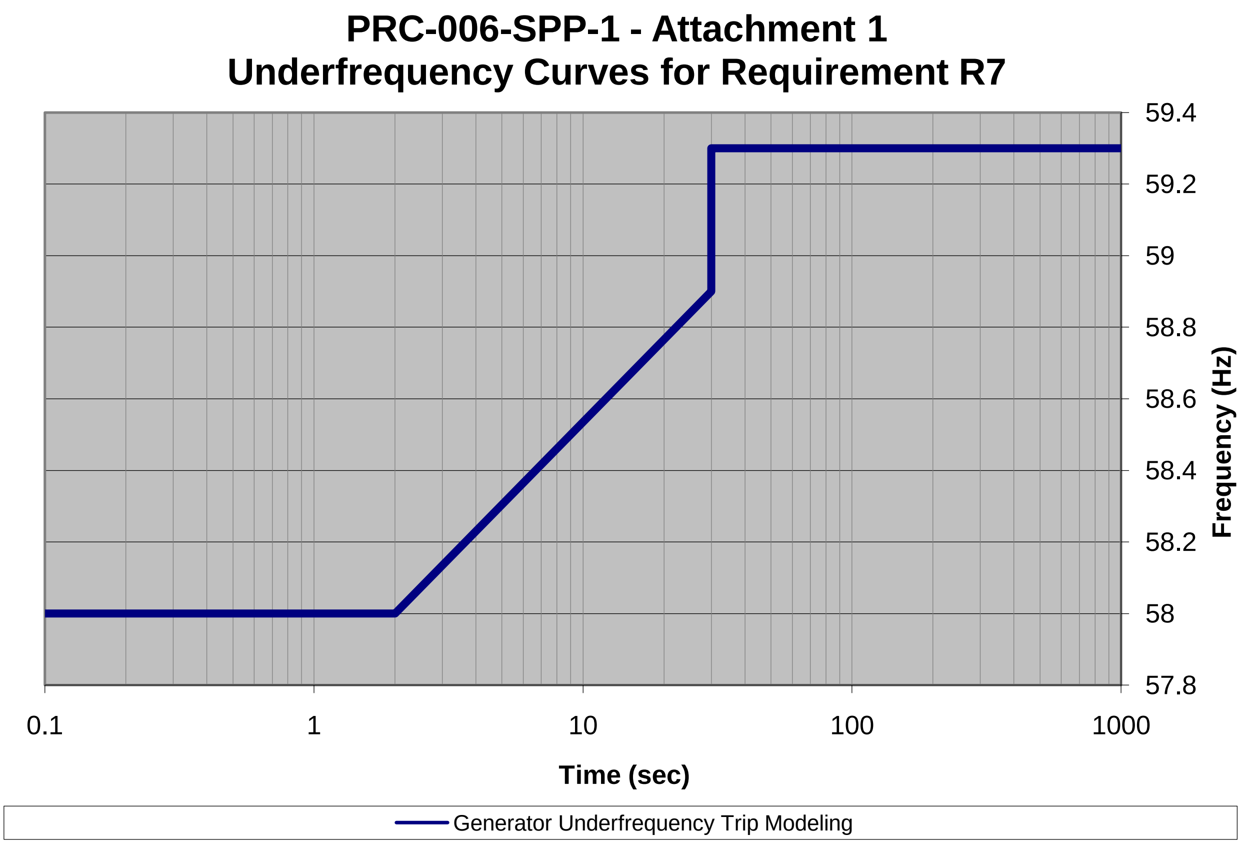
R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R7	Long-Term Planning	Medium	N/A	N/A	The Generator Owner did not provide technical evidence to the Planning Coordinator demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings for their generating units with operating characteristics that limit the unit's ability to perform in accordance with R7.	The Generator Owner did not verify that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2 due to the generator unit frequency protective relay settings.
R8	Long-Term Planning	Medium	N/A	N/A	The Planning Coordinator determined that the UFLS program was degraded in accordance with R8.1, but did not notify the Generator Owner or the UFLS entity of the Load that they were required to	The Planning Coordinator did not determine if the UFLS program performance was degraded due to the removal of any generation identified in accordance with R7.1 and verified in accordance with R8.

R #	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
					shed.	
R9	Long-Term Planning	Medium	N/A	N/A	N/A	The Generator Owner or other UFLS entity did not implement supplementary shedding of Load required by the Planning Coordinator in accordance with R8.1.1.

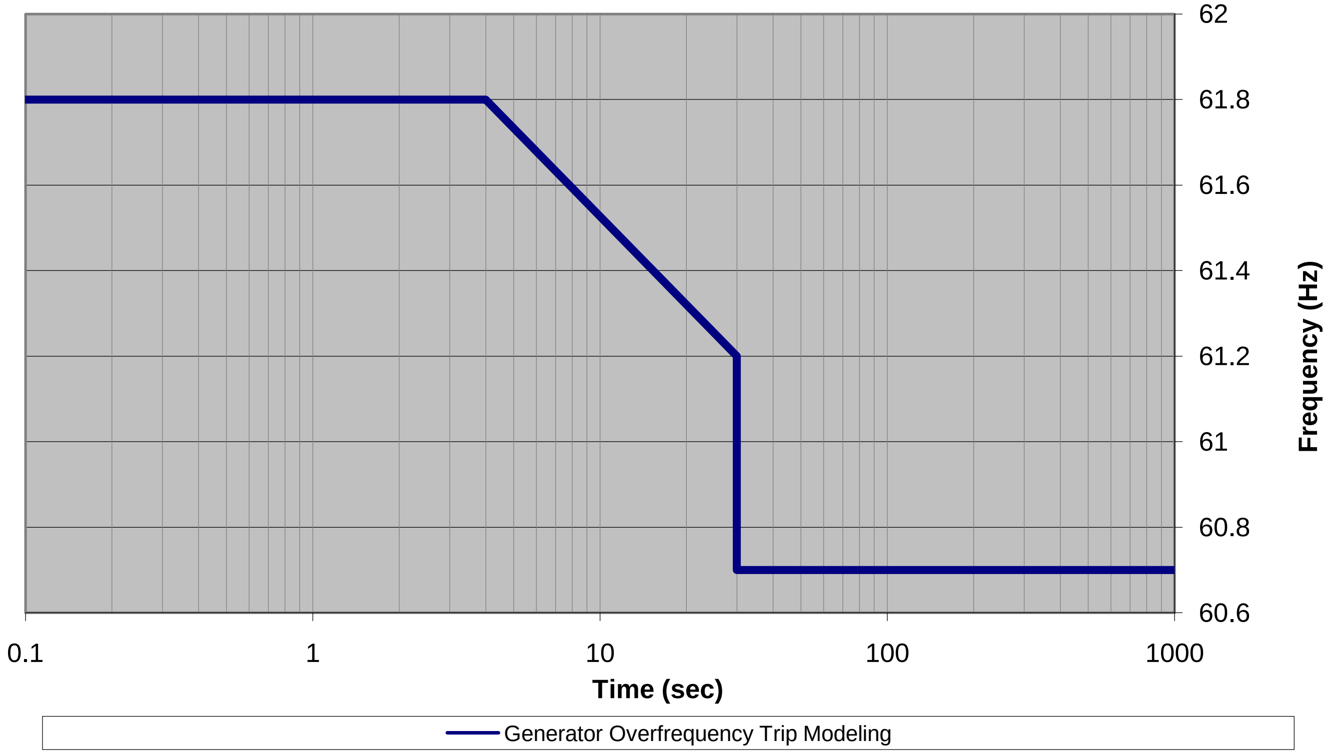
B. Associated Documents

Version History

Version	Date	Action	Change Tracking
Draft 1	3/31/2009 thru 4/30/2009	Posted for 1st Comment Period	Initial version
Draft 2	8/31/2009 thru 9/30/2009	Posted for 2nd Comment Period	Revised to address comments from Draft 1
Draft 3	3/29/2010 thru 4/28/2010	Posted for 3rd Comment Period	Revised to address comments from Draft 2
Draft 4	12/18/2010 thru 1/7/2011	Posted for 4th Comment Period	Revised to address comments from Draft 3
Draft 5	1/18/2011	Posted for 1st Open Vote	Revised to address comments from Draft 4
Draft 6	6/10/2011 thru 7/10/2011	Posted for 6th Comment Period	Revised to address comments from Draft 5
Draft 7	9/30/2011	Posted for 2nd Open Vote	Revised to address comments from Draft 6 and changed to results-based format


PRC-006-SPP-1 - Attachment 1
Underfrequency Curves for Requirement R7
59.4
59.2
59
58.8
58.6
58.4
58.2
58
57.8
Frequency (Hz)
0.1
1
10
100
1000
Time (sec)
Generator Underfrequency Trip Modeling

PRC-006-SPP-1 - Attachment 2
Overfrequency Curves for Requirement R7



SPP Regional Standard Request Form

RSR Number	RSR-001	RSR Title	UFLS
SPP Regional Standard Name (include Section No., Title, and existing Standard Version if any)	PRC-006-SPP-01		
Requested Resolution Date (if applicable)	N/A		
Description	PRC-006 (Development and Documentation of Regional UFLS programs) has been identified by NERC as one of the Regional (Fill-in-the Blank) Standards. The requirements developed in this standard at a minimum, need to meet the requirements for the Regional Program as identified in NERC's PRC-006-0. Operating experience and regional studies have resulted in a well developed UFLS program that is very resilient to frequency excursion resulting from severe and extreme contingencies. This standards development intends to effectively use the proven high performance characteristics of the existing SPP UFLS program and refine its requirements and coordination procedures through an open process involving SPP members and other entities materially affected by the reliability of the SPP Bulk Electric System.		
Reliability Need or Purpose – Try to identify if known: Technical requirements, reliability risk factor, measurements (refer to SPP Standards Process Manual for descriptions).	The purpose of writing this standard is to provide an adequate level of reliability for the bulk power system by implementing standards for the UFLS programs that are specific to the SPP area. The risk factor is high for this standard because a failure to meet this requirement could result in a system blackout. There will be three measurements for this standard. 1. The Transmission Owner shall have documentation of the UFLS program and current UFLS database. 2. The Transmission Owner 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. 3. The Transmission Owner shall have evidence it provided documentation of its assessment of its UFLS program to NERC as specified in Reliability Standard PRC-006-0_R3.		

Tariff Implications or Changes (Yes or No; If yes include a summary of impact and/or specific changes)	No changes to SPP Tariff.
Criteria Implications or Changes (Yes or No; If yes include a summary of impact and/or specific changes)	Yes, SPP Criteria 7.3 will be refined as to only refer to this regional standard.
NERC Standard Implications (Yes or No, and summary of impact)	No, the NERC UFLS SDT is preparing a pro forma document so that the detailed requirements will be left to each RE.

Sponsor	
Name	System Protection & Control Working Group (SPCWG)
E-mail Address	SPPSPCWG@spp.org
Company	Southwest Power Pool
Company Address	415 North McKinley, Little Rock, AR 72205
Phone Number	(501) 614-3564
Fax Number	(501) 666-0376

Proposed Regional Standard Language

Regional Reliability Standard Submittal Request

Region:	**Southwest Power Pool Regional Entity**
Regional Standard Number:	**PRC-006-SPP-01**
Regional Standard Title:	**SPP Automatic Underfrequency Load Shedding**
Date Submitted:	**8/13/12**
Regional Contact Name:	**Alice Wright**
Regional Contact Title:	**RE Manager, Finance and Process Improvement**
Regional Contact Telephone Number:	**501-688-1773**

Request (check all that apply):

- ☒ Approval of a new standard
- ☐ Revision of an existing standard
- ☐ Withdrawal of an existing standard
- ☐ Urgent Action

Has this action been approved by your Board of Directors[1]:

- ☒ Yes
- ☐ No

(If no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

[1] In accordance with the SPP RE Standards Development Process Manual, PRC-006-SPP-01 was presented to and approved by the SPP Regional Entity Trustees.

[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]	
Concise statement of the basis and purpose (scope) of request:	The proposed PRC-006-SPP-01 — SPP Automatic Underfrequency Load Shedding provides regional underfrequency load shedding requirements for registered entities in the SPP RE footprint. The purpose of PRC-006-SPP-01 is to ensure the development and maintenance of an effective and coordinated Automatic Underfrequency Load Shedding program in order to preserve the reliability and integrity of the bulk power system during declining system frequency events.
Concise statement of the justification of the request:	UFLS standards are basic, fundamental standards of prime importance to the reliability of the Bulk Power System. PRC -006-SPP-01 develops, coordinates, and documents requirements for automatic UFLS programs to arrest declining frequency and assist recovery of frequency following underfrequency events within the SPP RE footprint.

SPP Southwest Power Pool Regional Entity

SPP UFLS Standard: PRC-006-SPP-01

Standard Development Roadmap

Development steps completed per SPP RE Standards Development Process Manual

1. **SAR**
    - SPP System Protection and Control Working Group (SPCWG) presented Regional Standard Request -001 UFLS at the 10/17/07 Markets and Operations Policy Committee (MOPC) meeting.
    - MOPC approved the request for SPCWG to begin work on the standard as the Standard Drafting Team (SDT).

2. **Drafting and Balloting**
    - 1st draft posted for comment 3/31/09 to 4/30/09
        - SDT posted Response to 1st draft comments
    - 2nd Draft posted for comment 8/31/09 to 9/30/09
        - SDT posted response to 2nd draft comments
    - 3rd Draft posted for comment 3/29/10 to 4/28/10
        - SDT posted responses to 3rd draft comments
    - 4th Draft posted for comment 12/8/10 to 1/7/11
        - SDT posted responses to 4th Draft comments
    - 5th Draft posted for comment and voting
        - Ballot body registration 1/18/11 to 2/2/11
        - Voting 2/3/11 to 2/17/11
        - SDT posted Summary of Comments
        - Ballot Results: Weighted affirmative vote of 62%.
Vote failed (2/3 or 66.7% affirmative required to pass)
        - Standard returned to SDT
    - 6th Draft posted for comment 6/10/11 to 7/10/11
        - SDT posted responses to 6th Draft Comments
    - 7th Draft posted for comment and vote
        - Ballot body registration 9/30/11 to 10/14/11
        - Voting 10/15/11 to 10/29/11
        - SDT posted Responses to 7th Draft Comments
        - Ballot Results: Weighted affirmative vote of 76%
Vote passed (2/3 or 66.7% affirmative required to pass)

- Standard passed to MOPC

3. **MOPC Advisory Vote**
   - Consensus draft and minority report presented at 1/17/12 MOPC meeting for advisory vote.
   - **MOPC concurred** with consensus draft with 76.7% roll call vote

4. **Board of Directors/Members Committee Advisory Vote**
   - Consensus draft and minority report presented at 1/31/12 Board of Directors/Members Committee meeting
   - **Members Committee endorsed** SDT's recommendation to concur with standard
   - **Board Of Directors did not endorse** SDT's recommendation to concur with standard

5. **RE Trustees Action**
   - Trustees discussed at 4/23/12 meeting; deferred action to 7/30/12 meeting
   - At their 7/30/12 meeting, **Trustees unanimously approved PRC-006-SPP-01** for submittal to NERC

6. **Submittal to NERC**
   - SPP RE submitted standard to NERC for approval and filing with FERC on 8/13/12

Effective dates:

Requirements R4, R5, and R6 shall become effective the first day of the first calendar quarter one year after regulatory approval.

The remaining requirements shall become effective the first day of the first calendar quarter three years after regulatory approval.

Definitions of terms used in standard

There are no new or revised definitions proposed in this standard revision.

Southwest Power Pool

Regional Standard Drafting Team for PRC-006-SPP-01

Name and Title Affiliation Contact Info	Biography
Heidt Melson, SPCWG Chairman Manager Transmission Engineering Operation Xcel Energy 806-640-6356 heidt.melson@xcelenergy.com 6086 W. 48th Amarillo, TX 79109	Mr. Melson has 32 years of experience in the electric utility industry. Since 2002 he has been the Manager Transmission Engineering Operation for Xcel Energy. He manages a team of engineers and non-engineers and is responsible for commissioning new bulk power system equipment, transmission control room support, and transmission substation communication. Mr. Melson has designed, installed, and commissioned transmission projects from 69 to 345 kV and power plants up to 550 MW. He has experience conducting detailed analysis of system events and disturbances, improving correct protective relay operation, and meeting compliance requirements in three jurisdictions. Mr. Melson received his B.S.E.E. from Texas Tech University. He is a licensed Professional Engineer in Texas, Oklahoma, and New Mexico and a Master Electrician in Texas.
Edwin (Bud) Averill, SPCWG Member Project Engineer Grand River Dam Authority 918-825-0280 ext. 7743 baverill@grda.com PO Box 1128 Pryor, OK 74362	Mr. Averill has served in the electrical utility industry since 1971, when he began his career as an Electrical Engineer with Systems Engineering. He worked for Public Service Company of Oklahoma from 1972-1997 in several roles: Electrical Engineer/Project Manager, Electrical & Instrument-Control Supervisor, and Senior Electrical Engineer. Mr. Averill worked for Central and South West Services from 1997-2000 as a Senior Electrical Engineer for both System Protection and Substation Design. He worked at American Electric Power from 2000-2005 as a Senior Lead Engineer for Station Projects Engineering. Mr. Averill joined Grand River Dam Authority in 2005 and serves as a Project Engineer. Mr. Averill received his B.S.E.E. from Oklahoma State University and is a licensed Professional Engineer in Oklahoma. He belongs to and has served leadership roles with the Institute of Electrical & Electronic Engineers-Tulsa Section, Tulsa Engineering Foundation, and Tulsa Engineering Challenge. He also serves on the Electrical Board of Examinations and Appeals for the City of Tulsa and on the Board of Advisors-Electrical for Tulsa Junior College.
Brent Carr, SPCWG Member Senior Design Engineer-Transmission Design Arkansas Electric Cooperative Co. 501-570-2437 bcarr@aecc.com 1 Cooperative Way Little Rock, AR 72209	Mr. Carr has 11 years of experience with Arkansas Electric Cooperative Corporation and 6 years of previous experience in the manufacturing industry. As a Senior Design Engineer for Transmission Design, his responsibilities include preparing physical and electrical designs for power substations, conducting load and forecasting studies, managing projects, and developing equipment specifications and work contracts. Mr. Carr serves as a Board advisor for the University of Arkansas & University of South Carolina Grid-connected Advanced Power Electronics Systems research center and is Chairman of EPRI's Fault Current and Substation Grounding task force.

	Mr. Carr is a licensed Professional Engineer and Master Electrician in Arkansas. He received his B.S.E.E and M.S.E.E degrees from the University of Arkansas.
Louis Guidry, SPCWG Member Manager, NERC Compliance & Training Cleco Power LLC 318-484-7495 louis.guidry@cleco.com 2030 Donahue Ferry Road Pineville, LA 71360	Louis Guidry has been with Cleco for 26 years. His career at Cleco has included work related to substation design, communication systems, transmission system planning, transmission relaying and controls, system protection planning and design, and system protection apparatus maintenance. In 1998, Mr. Guidry was appointed Lead Engineer in his area, and in 2002 he became Manager of Electric System Maintenance. He held that position until his appointment as Director of Transmission and Distribution Reliability Compliance in 2006. Since 2006, Mr. Guidry has worked exclusively in the area of reliability compliance and recently was promoted to Manager of NERC Compliance and Training. In addition to his work experience at Cleco, Mr. Guidry is a licensed Professional Engineer and has earned the NERC Reliability Operator Certification. He serves on the SPP Members Compliance Group in addition to the SPCWG.
Rick Gurley, SPCWG Member Manager, Protection & Control Engineering American Electric Power 918-599-2263 RLGurley@aep.com 212 East 6th. Street Tulsa, OK 74119	Mr. Gurley has 32 years of experience in the electric utility industry and has served 28 years with AEP and its subsidiaries. He has worked in a number of areas including transmission and substation construction and maintenance, protection and control engineering, transmission planning, distribution operations, and transmission asset management. Mr. Gurley's current duties involve managing an engineering group responsible for the protection and control design of all substation projects in the western four states of AEP's service territory. Mr. Gurley is a licensed Professional Engineer in Texas. He is a member of the Industrial Advisory Board for the Electrical and Computer Engineering Department at Texas Tech University, a member of the NERC Protection System Misoperations Task Force, and a past member of the ERCOT System Protection Working Group.
Tim Hinken, SPCWG Member Supervisor of System Protection Engineering Kansas City Power & Light Company 816-245-3784 Tim.Hinken@kcpl.com 4400 East Front Street Kansas City, MO 64120	Tim Hinken has worked for Kansas City Power & Light for 31 years. He served six years as Supervisor of System Protection Engineering with responsibilities for supervising, designing, and coordinating protection systems. He served one year as Supervisor of Substation Engineering where he was responsible for supervising and designing substation construction projects. As a System Protection Engineer for five years, Mr. Hinken's responsibilities included material specification, design, coordination, and commissioning testing for generation protection systems, T&D substations, and distribution equipment. Mr. Hinken served 10 years as a Substation Engineer, responsible for design, material specification, and commissioning of substation construction projects. During his three years as a District Engineer his responsibilities included providing new or expanded electric service to commercial and industrial customers in the Kansas City area. Mr. Hinken has a B.S.E.E. from the University of Missouri Kansas City and a M.S.E.E. from the University of Missouri Columbia. He is a licensed Professional Engineer in Missouri and Kansas.

SPP Southwest Power Pool

Shawn Jacobs, SPCWG Member Lead Engineer Oklahoma Gas & Electric 405-553-5910 jacobssw@oge.com 3220 South High Oklahoma City, OK 73101	Shawn W. Jacobs is a Lead Engineer at Oklahoma Gas and Electric Company in Oklahoma City. He has 10 years of System Protection and Control experience at OG&E and is currently responsible for transmission/substation protective system settings and coordination, disturbance event/misoperation analysis, and NERC CIP and PRC compliance. Mr. Jacobs received his B.S.E.E. from the University of Oklahoma and is a licensed Professional Engineer in Oklahoma.
Ron McIvor, SPCWG Member Principal Protection Engineer Omaha Public Power District 402-552-4925 rmcivor@oppd.com 1101 N. 180th Street Elkhorn, NE 68022	Mr. McIvor has served OPPD for 35 years in the area of protective relaying. During his OPPD career he has served as Engineer, Senior Engineer, Relay Engineer, Lead Relay Engineer, and Lead Protection Engineer. In his present position as Principal Protection Engineer he is responsible for providing technical training to protection engineering staff and compliance with NERC PRC standards. Mr. McIvor is a licensed Professional Engineer in Nebraska, a Senior Member of IEEE, and a member of the Midwest Reliability Organization Protective Relay Subcommittee.
Lynn Schroeder, SPCWG Member Manager of Protection and Control Engineering Westar Energy, Inc. 316-291-8840 lynn.schroeder@westarenergy.com 4400 N. Seneca Wichita, KS 67204	Ms. Schroeder has 24 years of utility experience with Westar Energy. Before serving in her current role as Manager of the Protection and Control Engineering, she spent 16 years as a Protection and Control Engineer, three years as a Construction Supervisor, and two years as a Distribution Engineer. Ms. Schroeder has served 15 years as the Westar representative to the SPP SPCWG; for two of those years she served as chair. She also represents SPP on the NERC System Protection and Control Subcommittee. Ms. Schroeder has served as an Adjunct Professor for Wichita State University and Kansas State University, teaching Power System Analysis and Design and AC Circuits respectively. Ms. Schroeder has a B.S.E.E. and is a licensed Professional Engineer in Kansas.
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2010 Evaluation and Assessment of Southwest Power Pool (SPP) Under-Frequency Load Shedding Scheme

Powertech Project: 19993-21-00
Report No.: 19993-21-00-A

Prepared by:

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Executive Summary

Southwest Power Pool (SPP) retained Powertech Labs Inc. (PLI) to assess the performance of SPP's Under Frequency Load Shedding (UFLS) scheme as part of compliance requirements for UFLS programs as defined by NERC/SPP standards for under frequency load shedding. PLI conducted studies to assess the effectiveness of the existing UFLS program in the SPP power system. As part of NERC compliance every five years SPP should conduct a study, similar to the one reported herein, in order to provide evidence that SPP UFLS program is effective to cope with system changes. The last of such studies of the SPP system was conducted in the year 2006.

In this project, the UFLS relay data submitted by SPP members was reviewed and the SPP power system was studied under a number of scenarios with varying degree of mismatches between load and generation to evaluate performance of the UFLS scheme. The main findings of this study are summarized below:

- SPP has maintained and updated its UFLS relay data every five years (the last update was reported in 2006). This data includes sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.

- Review of the SPP members UFLS relay data revealed that relay set-points and amount of load shed in each stage closely follows the provisions of NERC/SPP requirements.

- The results of studies conducted and review of the relay data showed coordination exists between the UFLS program, under-voltage UFLS inhibit setting, generator under-frequency protection, and transmission protection.

- A number of scenarios with varying amount of generation/load mismatches were simulated, and in all of the simulations, the system frequency was adequately controlled and the SPP power system maintained reasonable stability. The result proved the adequacy of the UFLS program under the simulated scenarios.

- Simulation of over-shedding of up to 15%, in the most severe generation loss scenario (30% generation loss), showed the resultant over-frequency to be acceptable and no generator tripping due to over-speed is anticipated.

- The effect of universal UFLS scheme trip time setting was investigated. Scenarios with 30 and 40 cycles were simulated, and their results were reported and compared. The study indicated that with an intentional delay of 40 cycles (0.667 seconds) the UFLS program operates effectively and the SPP system maintains reasonable stability.

Overall, it is concluded that the SPP's UFLS scheme complies with the NERC/SPP requirements.

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1 Introduction

1.1 Application of Under Frequency Load Shedding Scheme

Power system steady-state operation requires a balance between generation and load. A sudden loss of generation due to abnormal conditions, such as loss of generating units due to faults, disturbs this balance and the system frequency begins to deviate from its nominal. System operation at low frequencies impairs the operation of power system components especially turbines and, if not corrected, can lead to tripping of additional generators thereby further aggravating the situation. To arrest frequency decline, the governors of the generators with spinning reserve attempt to make-up for the lost generation. If the frequency decline is too fast (due to severe mismatch between load and generation) and the governors cannot react fast enough or spinning reserve is not adequate, under-frequency relays are used for initiating automatic load shedding as a last resort to maintain system integrity by implementing an Under-Frequency Load Shedding (UFLS) program[1]. The under-frequency load shedding scheme must be properly designed to:

- Prevent excessive load shedding which may result in over-frequency conditions or unnecessary loss of service continuity and revenue,
- Avoid insufficient load shedding which in turn may lead to system blackout, and
- Provide sufficient load shedding to maintain the frequency within acceptable operating range.

Static analysis of power systems is widely used to design UFLS schemes. In such analysis, the equivalent inertia of the power system is obtained, the effect of voltage variation is ignored, and the whole system is assumed to be a single mass with parameters (such as load damping) being approximated by lumped values. Governor response of connected generation is also ignored for the sake of simplicity. The simplicity of static analysis makes it useful for rapid evaluation of numerous UFLS schemes to select a few designs that result in acceptable performance over a wide range of conditions. However, for detailed assessment of UFLS schemes, dynamic simulation is required. The more detailed revelation of system response makes dynamic analysis useful for in depth analysis of a short list of alternative UFLS schemes.

A coordinated automatic under-frequency load shedding program is required to maintain power system security during major system frequency declines. The North American Electric Reliability Council (NERC) has provided Reliability Standards, Requirements, Measures and Levels of Compliance to ensure the proper implementation of UFLS programs. NERC regional members have developed their own standards based on the NERC standards that also address their specific needs. For the sake of completeness, NERC and SPP polices regarding UFLS program are reproduced in Appendix A & B respectively.

[1] Load shedding is an *emergency control action* typically implemented to recover a system from *Emergency* state to *Normal* state.

1.2 Objectives

As part of compliance with the NERC and SPP requirements for UFLS program, Southwest Power Pool (SPP) contracted Powertech Labs Inc. (PLI) to evaluate the performance of their UFLS scheme. The objectives of this study are as follows:

- To review and convert SPP's under frequency relay data into a format suitable for use for time-domain simulations.
- To conduct simulations on the SPP power system to determine if the SPP UFLS scheme is compliant with the NERC/SPP requirements in maintaining system security under severe imbalance between load and generation scenarios.
- To determine if the SPP system remains stable for up to 45% load shedding.
- To determine sensitivity results with respect to a few intentional time delays in UFLS program.
- To recommend modifications to the SPP UFLS scheme if deemed necessary.
- To determine the effect of under-voltage inhibit setting of no greater than 85% nominal voltage on the UFLS program.
- To provide documentation detailing the results of the study.

2 Scope and Study Approach

The scope of this project includes review of the SPP UFLS program to verify its performance against NERC and SPP criteria, and recommend modifications if needed. The evaluation is to be performed with a time-domain simulation program using SPP submitted powerflow, dynamic data and the UFLS relay data. The present study focuses on the SPP region and does not consider UFLS schemes outside of SPP.

The study will examine system performance over the time period needed for the UFLS relays to operate, but will not include AGC action or a full study of system islanding scenarios.

2.1 Modeling Requirements

Accurate UFLS performance evaluation requires simulation of power systems in the time-domain under several severe imbalance conditions between generation and load. It is therefore important to model the dynamics of the power system components in detail. The dynamic representations of the following power system components are most crucial in UFLS evaluation:

- UFLS relays including generator under-frequency protection and under-frequency system islanding schemes,
- Generators including their spinning reserve,
- Governors and turbines,
- Excitation systems,
- Loads with frequency/voltage dependency.

In the UFLS evaluation studies, representation of dynamic action of Under Load Tap Changing transformers (ULTC) is not necessary since their response times are much longer than the time frame of UFLS operations. The dynamic models of over/under excitation limiters are also not required as long as reactive power of generators are monitored and units with reactive power exceeding their reactive power capabilities are identified and disconnected if the under/over excitation condition is sustained.

The dynamic data submitted by SPP was reviewed and found adequate in regard to the dynamic representation of power system components described above. The submitted UFLS relay data was reviewed and all models relevant to the study were generated and incorporated into the system model. A commonly accepted frequency dependent load model was also adopted in this study (3.4).

2.2 Selection of Appropriate Scenarios in the UFLS Assessment

The powerflow basecase, Summer 2011, submitted by SPP is implemented as the loading condition for the system under the study. For this loading condition, three scenarios of generation/load imbalances were developed. These scenarios were designed to fully exercise the UFLS program to assess compliance with NERC and SPP standards. This calls for examination of several levels of imbalance between generation and load to trigger different levels of load shedding stages. Time-domain simulations were conducted for generation loss scenarios. Extensive monitoring and analysis of the simulations were performed to ensure that the frequency declines are properly arrested and system security is maintained.

2.3 Tools Used to Assess the UFLS scheme

In this project, the Transient Security Assessment Tool (TSAT) developed by Powertech Labs Inc. was used to evaluate the effectiveness of the SPP UFLS program. TSAT is a time-domain simulation program with comprehensive modeling capabilities that accepts system data in (Siemens/PTI) PSS/E data format. Powertech's powerflow program, Powerflow & Short circuit Analysis Tool (PSAT), was also used to reduce the NERC powerflow basecase to include only the SPP power system.

3 Model Assembly and Data Sanity Checking

3.1 Powerflow Basecase

SPP provided one powerflow basecase. This powerflow corresponds to the 2011 peak load condition. The powerflow results summary (ordered in terms of SPP areas) for this basecase is provided in Table 3-1.

Table 3-1: Power Flow Summary for Peak Load of Year 2011

Area		Generation		Load		Losses		Export	
Number	Name	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
502	CELE	2894.76	1124.40	2505.28	666.84	66.40	632.99	405.85	375.08
503	LAFA	222.79	40.00	485.47	19.07	7.32	84.98	-270.00	-51.38
504	LEPA	161.06	19.28	225.00	7.87	0.06	0.15	-64.61	11.30
515	SWPA	1993.68	517.67	898.60	243.50	34.17	377.95	1061.19	239.72
520	AEPW	9460.07	1319.17	10339.80	1906.39	271.79	2914.30	-1136.79	249.36
523	GRDA	1121.08	179.37	1029.49	210.69	19.55	330.01	70.71	-68.54
524	OKGE	7320.33	903.75	6324.73	1521.24	150.53	1850.11	836.88	283.87
525	WFEC	1204.02	104.93	1382.50	364.47	50.35	346.92	-229.87	-196.30
526	SWPS	5895.59	814.91	5936.61	1344.16	202.45	1739.59	-245.23	-2.67
527	OMPA	55.72	21.96	666.35	133.28	2.36	15.25	-613.40	-115.28
531	MIDW	124.61	13.66	376.45	79.60	8.50	27.98	-238.47	-29.54
534	SUNC	544.26	1.73	451.60	145.50	17.40	170.84	7.44	4.95
536	WERE	6101.78	999.06	6014.75	1481.11	136.54	1858.83	-176.02	-210.13
539	WEPL	387.51	13.73	678.40	201.80	21.48	139.37	-189.72	83.46
540	MIPU	1156.59	402.71	2101.40	654.12	31.82	375.84	-932.03	-108.01
541	KACP	4327.93	1251.68	3515.62	800.46	69.92	1188.45	726.01	193.81
542	KACY	574.77	65.87	554.03	126.34	3.74	84.95	16.99	-132.51
544	EMDE	1122.64	100.06	1177.49	122.59	38.12	277.80	-92.97	20.09
545	INDN	216.87	10.41	322.44	80.97	2.44	21.85	-108.03	-58.84
546	SPRM	741.80	352.30	784.85	269.78	9.97	166.26	-53.24	19.17
640	NPPD	3118.84	93.69	3659.72	1131.30	127.03	1186.02	-667.92	133.08
645	OPPD	3273.60	1082.58	2972.12	958.73	34.52	681.68	266.94	-40.29
650	LES	262.91	24.00	803.40	159.50	9.51	165.75	-549.98	5.10
	TOTAL:	52,283.21	9,456.92	53,206.10	12,629.32	1,316.00	14,637.87	-2,176.25	605.50

3.2 Model reduction

The powerflow basecase submitted by SPP contain all regions of NERC power system. To be able to assess the adequacy of the UFLS program in the SPP region, it is necessary to create scenarios in which large mismatches between generation and load exist. Modeling the entire NERC network for these types of scenarios presents two practical problems:

(i) The amount of mismatch between generation and load would have to be significantly substantial to observe large frequency excursion (note NERC load is ~670,000 MW) which is considered unrealistic unless islanding scenarios are explicitly considered.

(ii) To judge the performance of UFLS program in SPP, load shedding relays in all of NERC regions would have to be modeled. This is considered impractical for this type of study.

Because of aforementioned limitations, a practical approach is to deal with a reduced system model in which only the SPP network is explicitly represented and SPP network imports or exports to the rest of the NERC system are replaced with equivalent generation or loads ("block loaded").

Therefore, a powerflow based network reduction technique was used in which all tie lines to/from SPP are replaced with equivalent power flow injections at the tie line ends. In this process a few islands with a small number of buses were created. These islands were ignored as a new basecase was created for SPP power system. With this setup, the tie-line flows could be changed to represent disturbances in the NERC system resulting in additional generation/load mismatch seen by the SPP system.

<u>Note regarding reduction process</u>:

The reduction process rendered a system with 19 islands. The largest island, which considered as the main system, contained 6,207 buses. This island was considered as the basecase throughout this report. The additional 18 islands were reasonably small as they mostly contain two or three buses, with a total of 25 buses from SPP areas. These buses were completely located within non-SPP areas with no direct connection to any SPP bus. These islands were not incorporated within this study and not reported in this context.

The following table provides a comparison between the complete and reduced basecase powerflow results for SPP areas generation and load.

Table 3-2: Powerflow summary for the Complete and Reduced basecases

Area		Generation (MW)		Load (MW)	
Number	Name	Orig.	Reduced	Orig.	Reduced
502	CELE	2,894.76	2,894.76	2,505.28	1,851.98
503	LAFA	222.79	222.79	485.47	485.47
504	LEPA	161.06	47.06	225.00	61.00
515	SWPA	1,993.68	1,941.38	898.60	898.60
520	AEPW	9,460.07	9,460.07	10,339.80	10,135.02

Area		Generation (MW)		Load (MW)	
Number	Name	Orig.	Reduced	Orig.	Reduced
523	GRDA	1,121.08	1,121.08	1,029.49	1029.49
524	OKGE	7,320.33	7,320.33	6,324.73	6,324.73
525	WFEC	1,204.02	1,204.02	1,382.50	1382.50
526	SWPS	5,895.59	5,895.59	5,936.61	5,936.61
527	OMPA	55.72	55.72	666.35	666.35
531	MIDW	124.61	124.61	376.45	376.45
534	SUNC	544.26	544.26	451.60	451.60
536	WERE	6,101.78	6,101.78	6,014.75	6,014.75
539	WEPL	387.51	387.51	678.40	678.40
540	MIPU	1,156.59	1,156.59	2,101.40	2,101.40
541	KACP	4,327.93	4,327.93	3,515.62	3,515.62
542	KACY	574.77	574.77	554.03	554.03
544	EMDE	1,122.64	1,122.64	1,177.49	1,177.49
545	INDN	216.87	216.87	322.44	322.44
546	SPRM	741.80	741.80	784.85	784.85
640	NPPD	3,118.84	3,118.84	3,659.72	3,659.72
645	OPPD	3,273.60	3,273.60	2,972.12	2,972.12
650	LES	262.91	262.91	803.40	803.40
	TOTAL:	52,283.21	52,117.14	53,206.10	52,124.99

Note: The reduced system parameters are used throughout this report unless otherwise noted.

3.3 Basecase Small Signal Stability

Single Machine Infinite Bus (SMIB) analysis was performed on the 2011 basecase, to determine if system contains any significant or unusual local modes of oscillation. These modes are typically an indication of possible discrepancy within dynamic data such as generator models, its associated controls such as exciter, governor, or power system stabilizer (PSS).

The results of SMIB analysis on the basecase revealed that a unit located in Area 515 (SWPA) at bus 505436, ID:1, had a local mode at a frequency of 0.0238 Hz with negative damping ratio of 4.2%. After examination of the unit dynamic data, it was suspected that the exciter output feedback gain K_E (type IEEET1) might have contributed to this negative damping. In order to implement automatic calculation for K_E at the program initialization, K_E was set as zero. Setting parameter K_E to zero initiates an automatic calculation process within the program to derive a suitable value for K_E. Following this modification, the final SMIB analysis results were acceptable. The mentioned generator mode was observed to have a positive damping of 100% at zero hertz frequency.

3.4 Load models

Static load models were added to the dynamic data based on ZIP (constant impedance, constant current, constant power) model. For all SPP areas, the constant current load model was used for the real component of load and constant impedance was used for the reactive component of load. Frequency dependency coefficients of 1%[2] and –1% were assumed for the real and reactive components of the load models, respectively.

3.5 Relay Model Conversion

SPP provided UFLS relay data for its members in the MS Excel program format. The Excel file is referred to as the Control Area Workbook (CAW). The CAW is used by SPP members to document their UFLS relay data, as required by section 7.3 of the SPP Criteria (see Appendix B). Table 3-3 lists the SPP members and shows which members submitted their UFLS relay database.

Table 3-3: SPP Member UFLS Relay Data Submission Status

No	Area Abbreviation	Area Number	Area Name	Data Submitted	%Total SPP Peak Load
1	CELE	502	Cleco Power, LLC	Y	4.7
2	LAFA	503	City of Lafayette, LA	Y	0.9
3	LEPA	504	Louisiana Energy & Power Authority	N	0.4
4	SWPA	515	Southwestern Power Administration	Y	1.7
5	AEPW	520	American Electric Power West	Y	19.4
6	GRDA	523	Grand River Dam Authority	Y	1.9
7	OKGE	524	OG&E Electric Services	Y	11.9
8	WFEC	525	Western Farmers Electric Coop	Y	2.6
9	SWPS	526	Southwestern Public Service Company	Y	11.2
10	OMPA	527	Oklahoma Municipal Power Authority	Y	1.3
11	MIDW	531	Midwest Energy, Inc	Y	0.7
12	SUNC	534	Sunflower Electric Power Corporation	Y	0.8
13	WERE	536	Western Energy, Inc	Y	11.3
14	MKEC	539	Mid-Kansas Electric Company	Y	1.3
15	MIPU	540	Missouri Public Service	Y	3.9
16	KACP	541	Kansas City Power & Light Company	Y	6.6
17	KACY	542	Board of Public Utilities	Y	1.0
18	EMDE	544	Empire District Electric Company	Y	2.2
19	INDN	545	City Power & Light	Y	0.6
20	SPRM	546	City Utilities, Springfield, MO.	Y	1.5
21	NPPD	640	Nebraska Public Power District	Y	6.9
22	OPPD	645	Omaha Public Power District	Y	5.6
23	LES	650	Lincoln Electric System	Y	1.5

As shown in Table 3-3 almost all SPP members provided UFLS relay data. The only member with no UFLS data, area 504, represents about 0.4% of total SPP peak load. Although this area was included in the study, no UFLS data was considered for this area.

[2] E.g., 1% frequency change causes 1% change in load

The submitted relay data included the following relay types:

- Under-frequency load shedding (up to 5 stages with and w/o remote line/generator tripping).
- Over-frequency generator tripping.
- Under-frequency generator tripping.

The submitted CAW's were checked for errors and discrepancies to validate the relay data entries. As part of the validation process, the following issues were examined:

- Invalid bus #'s, load ID's or circuit ID's by comparison to powerflow basecase.
- Duplicate Bus# entries with the same load ID's.
- Unusual under-frequency setpoints (f << 58.7 or f >> 59.3).
- Unusually long operating times (relay or breaker).
- Issues with shedding ratios such as ratio scale or sum greater than 100%.
- Redundant and conflicting data.
- Buses with no load or generations with relay setting.
- Any required entries that were left blank.

The issues regarding the aforementioned data along with suggestions that could be used to resolve them were submitted. Once the CAW files were validated, a set of Visual Basic macros were developed to extract and format the relay data into text files that are acceptable by TSAT and/or Siemens/PTI PSS/E software.

SPP standard (see Appendix B) regarding the UFLS program requires the under-frequency relay set-points to closely adhere to the following three stages shown in Table 3-4.

Table 3-4: Under frequency Load Shedding Stages Defined by SPP

Stage	Frequency set-point Hz	% Load Shed
1	59.3	10
2	59.0	10
3	58.7	10

This criterion implies that at least 30% of loads in the SPP power system should be allocated for the load shedding scheme to account for the generation/load imbalance of up to 30%. Also, the load shed should be distributed over a minimum of three stages.

The submitted relay data was analyzed for coherence with the SPP UFLS stages. The results are provided in Table 3-5. It should be noted that reported quantities in Table 3-5 only include bus load shedding, thus load shedding due to circuit tripping is not reflected in this table, but considered in the simulations. In actuality, as is noted in a paragraph below, there is more UFLS (load shedding) than reflected in Table 3-5. The extra load shedding results because, per the excel spreadsheet for UFLS, there are direct trips of circuits. These extra circuits that were tripped by UFLS were not identified as to the MW load tripped and were not included in Table 3-5. It should also be noted that pick up delay times are not reflected in Table 3-5.

Table 3-5: UFLS relay summary

Load condition		Total load MW	Stage 1: f ≥ 59.3 Hz		Stage 2: 59.3 > f ≥ 59 Hz		Stage 3: f < 59 Hz		Total UF load shedding	
			MW	%	MW	%	MW	%	MW	%
2011 Summer total SPP		53,206	5,722.6	10.8	5,235.5	9.8	6,641.9	12.5	17,600.0	33.1
502	CELE	2,505.3	235.6	9.4	251.3	10.0	213.1	8.5	700.1	27.9
503	LAFA	485.5	3.4	0.7	3.3	0.7	2.5	0.5	9.2	1.9
504	LEPA	225.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
515	SWPA	898.6	38.5	4.3	0.0	0.0	0.0	0.0	38.5	4.3
520	AEPW	10,339.8	1,039.4	10.1	913.2	8.8	1,054.0	10.2	3,006.6	29.1
523	GRDA	1,029.5	149.4	14.5	147.6	14.3	134.6	13.1	431.6	41.9
524	OKGE	6,324.7	1,029.2	16.3	851.7	13.5	859.2	13.6	2,740.2	43.3
525	WFEC	1,382.5	158.6	11.5	183.3	13.3	174.4	12.6	516.3	37.3
526	SWPS[3]	5,936.6	599.5	10.1	505.1	8.5	641.3	10.8	1,745.9	29.4
527	OMPA	666.4	54.7	8.2	64.0	9.6	75.4	11.3	194.0	29.1
531	MIDW[4]	376.5	53.4	14.2	0.0	0.0	29.0	7.7	82.4	21.9
534	SUNC	451.6	58.3	12.9	38.0	8.4	39.0	8.6	135.3	30.0
536	WERE	6,014.8	805.2	13.4	772.8	12.8	937.2	15.6	2,515.2	41.8
539	MKEC	678.4	58.1	8.6	48.8	7.2	85.9	12.7	192.8	28.4
540	MIPU	2,101.4	274.0	13.0	242.8	11.6	294.0	14.0	810.8	38.6
541	KACP	3,515.6	408.3	11.6	420.6	12.0	345.1	9.8	1,174.0	33.4
542	KACY	554.0	47.5	8.6	65.4	11.8	61.0	11.0	173.9	31.4
544	EMDE	1,177.5	124.9	10.6	104.0	8.8	227.8	19.3	456.6	38.8
545	INDN	322.4	2.2	0.7	1.3	0.4	1.4	0.4	4.8	1.5
546	SPRM	784.9	111.7	14.2	75.5	9.6	93.3	11.9	280.6	35.7
640	NPPD	3,659.7	267.2	7.3	305.4	8.3	236.0	6.4	808.6	22.1
645	OPPD	2,972.1	201.8	6.8	239.9	8.1	1,135.8	38.2	1,577.5	53.1
650	LES	803.4	1.7	0.2	1.5	0.2	1.9	0.2	5.1	0.6

Note: To produce this table the submitted relay data was treated as follows: Stage 1: Freq ≥ 59.3 Hz, Stage 2: 59.0Hz ≤ Freq < 59.3 Hz, Stage 3: Freq < 59.0 Hz.

As shown in Table 3-5, the distribution of the relay set-points defined in the CAW closely adhere to the recommended SPP load shedding stages defined in Table 3-4. In summary, the settings and

[3] Dropped load as a result of circuit tripping were included for this member. The circuit tripping as reported by SPP for stage 1, 2 and 3 were 378.3 MW, 181.7 MW and 385.6 MW respectively.
[4] Dropped load as a result of circuit tripping were included for this member. The circuit tripping as reported by SPP for stage 1 was 35.4 MW.

amount of load shed defined in the relay data are resonantly close to the requirement defined in Table 3-4.

A review of the UFLS scheme derived from the above table indicates that:

1- Areas LAFA, LEPA, SWPA, MIDW, INDN, NPPD and LES have scheduled UFLS ratios substantially lower than 30%.
2- However, SPP (combined areas) closely follow the NERC/SPP UFLS standard.

Upon completion of this study the following two pieces of information were reported to PLI.

1- As reported by SPP, a number of its members, including LAFA, INDN, and LES, submitted their UFLS data in percentage of on their total system load instead of the load at each particular bus. This was determined to be the cause for low amount of load shed for these members in Table 3-5. It should be mentioned that the total load for these three members equals about 3% of SPP's total load, which is reasonably small as compared within SPP's overall UFLS program. Therefore it is not anticipated that such a discrepancy alter the results of this study.
2- SWPA and LEPA do not own or operate any UFLS equipment. All UFLS equipment for these two members is operated by other members and is not included in this study.

4 Simulations and Analysis

To study the dynamic behavior of the SPP UFLS scheme, a number of scenarios were designed to create different levels of mismatch between generation and load. To achieve the desired level of mismatch, scenarios were developed by disconnecting a number of imports to SPP and a number of generators to arrive at the target amount of mismatch between load and generation. There were three levels of generation loss considered, namely, 10%, 20% and 30%. Table 4-1 summarizes the amount of generation disconnected in 2011 basecase to achieve the 10%, 20% and 30% generation loss (GL) scenarios.

Table 4-1: The Studied Generation Loss Scenarios

Power Flow Base Case	Case ID	Imports lost (MW)	Gen. tripping (MW)	Total Gen. Lost (MW)
2011	2011_10%	4806.60	550.77	5357.37
	2011_20%	4806.60	5,909.86	10716.46
	2011_30%	4806.60	11,468.92	16275.52

The dynamic response of the SPP power system following 10%, 20% and 30% generation loss was simulated using PLI's TSAT program. In these simulations the following models and assumptions were used:

(1) The reduced power system model of NERC (SPP network only) was used as powerflow basecase.

(2) All converted relays models were incorporated within the simulations.

(3) Loads were modeled by constant current model for active power and constant impedance model for reactive power. Load active power is assumed to reduce by 1% for 1% frequency drop, and load reactive power is assumed to increase by 1% for 1% frequency drop.

(4) Simulations were performed for a period of 20 seconds for all of the scenarios.

Table 4-2 provides a summary of the simulation results for each scenario. The third column is simply the ratio of load shed to the generation lost (percentage of load shed to generation lost) and may be used to identify over shedding cases.

Table 4-2: Simulation result summary for three Scenario Disturbances

Load condition	Scenario ID	100*(Load Shed/Gen. Lost) (%)	Load shed by UFLS relays MW	Minimum load frequency range (Hz)	
				Lower	Upper
2011	2011_10%	0	0	59.5655	59.7412
	2011_20%	51	5,449	58.9549	59.2985
	2011_30%	82	13,384	58.4876	59.1178

It should be noted that the action of AGC (Automatic Generation Control) was not modeled in any of the simulations. Therefore, the frequency response is only due to primary/governor response.
The following sections discuss, in detail, the SPP UFLS results for the 10%, 20% and 30% generation loss scenarios the 2011 basecase.

4.1 Analysis of 10% Generation Loss

Selection of Simulation Scenario

The list of SPP generators that are disconnected in the dynamic simulation to achieve 10% generation loss scenario are shown in Table 4-3.

Table 4-3: Scenario ID 2011_10%GS

Generation Shed for Scenario 2011_10%						
No.	**Area#**	**Area Name**	**Bus #**	**Bus Name**	**Gen ID**	**MW**
1	503	LAFA	502435	HARGIS1 13.8	1	49.79
2			502436	HARGIS2 13.8	1	49.79
3	504	LEPA	503301	MRGNCTY4 138.	3	10.49
4	515	SWPA	505404	MALDEN 2 69.0	1	7.00
5			505408	KENNETT2 69.0	1	7.50
6			505414	PARAGLD2 69.0	1	5.50
7			505417	JNSBGEN1 13.8	1	21.00
8			505417	JNSBGEN1 13.8	2	21.00
9			505419	JNSBGEN2 13.8	1	40.00
10			505424	GF #1 1 13.8	1	49.60
11			505426	GF #2 2 13.8	2	49.60
12			505432	SIKGEN 1 13.8	1	235.00
13			505436	POP BLF2 69.0	1	4.50
					Total:	550.77

The sum of the above generation loss (550.77 MW) plus the import loss (4,806.60 MW) accounts for 10% generation loss required for this scenario. It should be noted that not all of the units listed above were originally planned for generator tripping scenarios. However, it was necessary to trip some units beyond those planned in order to avoid local problems.

Simulation Results

Table 4-4 shows area-by-area load shedding as a result of generation loss (10% GS scenario) for the 2011 basecase.

Table 4-4: Load Shedding Summary by Area For Scenario ID 2011_10%GS

Area	Name	Initial Load (MW)	Load Shed (MW)	Final Load (MW)	Load Shed (%)	Initial Gen. (MW)	Gen. Shed		Final Gen (MW)	Spinning Reserve Used (MW)
							Scheduled (MW)	UFLS (MW)		
502	CELE	1,852	0	1,852	0.0	2,895			3,178	283
503	LAFA	485	0	485	0.0	223	100		136	13
504	LEPA	61	0	61	0.0	47	10		37	1
515	SWPA	899	0	899	0.0	1,941	441		1,662	161
520	AEPW	10,135	0	10,135	0.0	9,460			10,332	872
523	GRDA	970	0	970	0.0	1,121			1,184	63
524	OKGE	6,325	0	6,325	0.0	7,320			7,863	543
525	WFEC	1,383	0	1,383	0.0	1,204			1,289	85
526	SWPS	5,937	0	5,937	0.0	5,896			6,257	362
527	OMPA	666	0	666	0.0	56			59	3
531	MIDW	376	0	376	0.0	125			127	3
534	SUNC	452	0	452	0.0	544			584	39
536	WERE	6,015	0	6,015	0.0	6,102			6,671	569
539	MKEC	678	0	678	0.0	388			419	31
540	MIPU	2,101	0	2,101	0.0	1,157			1,296	140
541	KACP	3,516	0	3,516	0.0	4,328			4,643	315
542	KACY	554	0	554	0.0	575			583	8
544	EMDE	1,177	0	1,177	0.0	1,123			1,151	28
545	INDN	322	0	322	0.0	217			237	20
546	SPRM	785	0	785	0.0	742			827	86
640	NPPD	3,660	0	3,660	0.0	3,119			3,330	212
645	OPPD	2,972	0	2,972	0.0	3,274			3,389	116
650	LES	803	0	803	0.0	263			294	31
							551			
	Import					4,807	4,807			
	Others									
	Total	52,125	0	52,125	0.0	56,923	5,357		55,548	3,983

Note: Spinning reserves used in the last column is equal to final generation (MW) minus generation shed (MW) minus initial generation (MW).

Figure 4-1 shows the monitored SPP load bus frequencies for the 2011 basecase. It can be seen that the frequency does not fall below first stage, 59.3 Hz, of UFLS setting. The system frequency finally stabilizes to approximately 59.76 Hz.

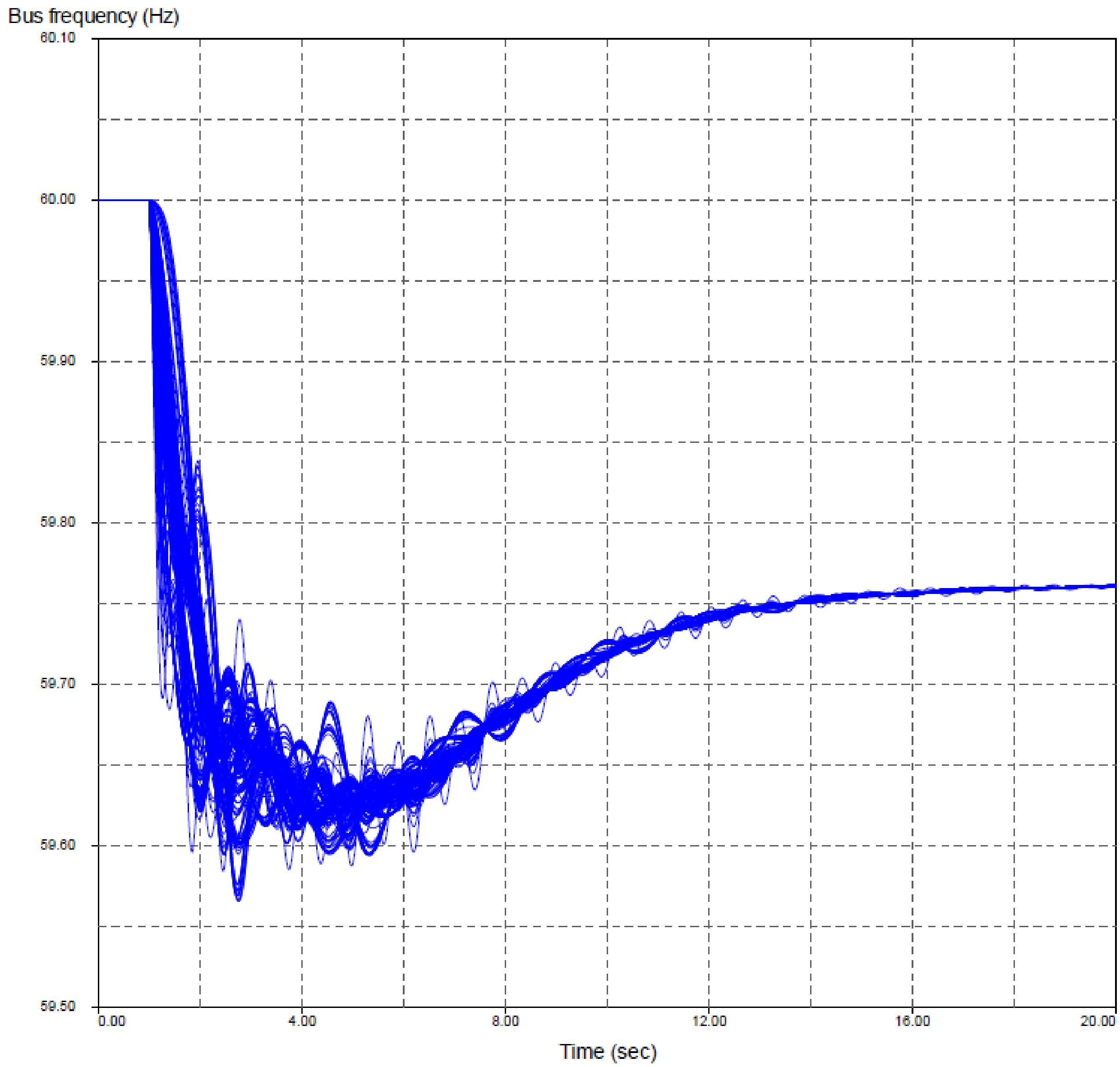

Figure 4-1: Load Bus Frequency Response Scenario 2011_10%GS

Table 4-5 shows a summary of the results for the 2011 basecase 10% generator shedding scenario.

Table 4-5: Load Shedding Summary for Scenario ID 2011_10%GS

TSAT Results (MW)	
Load Shed by UFLS	0
Load Reduction due to Voltage & Frequency	1,145.12
Generation Shed	5,357.37
Spinning Reserve Used	3,982.56

The above results show that for the 10% generation loss scenario, no load is shed by the UFLS scheme. This is attributed to small generation loss compared to the presence of rather large amount of spinning reserve and load relief due to voltage and frequency which caused the system frequency not to drop below the first stage of UFLS scheme.

4.2 Analysis of 20% Generation Loss

Selection of Simulation Scenario

The 20% generation loss scenario is similar to the 10% generation loss scenario described in the previous section with the exception of tripping additional SPP generators to create overall 20% generation loss. Table 4-6 lists the additional units that were disconnected in the dynamic simulations to achieve 20% generation loss scenario.

Table 4-6: Scenario ID 2011_20%GS

Additional Generation Shed for Scenario 2011_20%						
No.	**Area#**	**Area Name**	**Bus #**	**Bus Name**	**Gen ID**	**MW**
1	502	CELE	500205	G1COLUMB 13.8	1	17.70
2	520	AEPW	509394	FLINTCR1 21.0	1	500
3			509404	WELSH1-1 18.0	1	500
4			509406	WELSH3-1 18.0	1	500
5	524	OKGE	514805	SOONER1G 22.0	1	540
6			515225	MUSKOG5G 18.0	1	517
7	526	SWPS	525561	TOLK_1 124.0	1	469.59
8			525562	TOLK_2 124.0	1	540
9	536	WERE	532652	JEC U2 26.0	1	705
10			532722	EEC U2 24.0	1	370
11	541	KACP	542951	HAW G5 1 22.0	5	550
12	640	NPPD	640090	BROKENBG 69.0	1	8.30
					Total:	5,217.59

Simulation Results

The results of time-domain simulation run for 20% generation loss scenario corresponding to the 2011 basecase are summarized in Table 4-7.

Table 4-7: Load Shedding Summary by Area For Scenario ID 2011_20%GS

Area	Name	Initial Load (MW)	Load Shed (MW)	Final Load (MW)	Load Shed (%)	Initial Gen. (MW)	Gen. Shed		Final Gen (MW)	Spinning Reserve Used (MW)
							Scheduled (MW)	UFLS (MW)		
502	CELE	1,852	177	1,675	9.6	2,895	18		3,224	347
503	LAFA	485	3	482	0.7	223	100		139	16
504	LEPA	61	0	61	0.0	47	10		37	1
515	SWPA	899	39	860	4.3	1,941	441		1,700	200
520	AEPW	10,135	1,039	9,096	10.3	9,460	1,500		8,862	902
523	GRDA	970	149	821	15.4	1,121			1,196	75
524	OKGE	6,325	1,018	5,307	16.1	7,320	1,057		6,840	577
525	WFEC	1,383	128	1,254	9.3	1,204			1,306	102
526	SWPS	5,937	440	5,497	7.4	5,896	1,010		5,250	364
527	OMPA	666	55	612	8.2	56			59	4
531	MIDW	376	53	323	14.2	125			128	3
534	SUNC	452	57	395	12.6	544			585	41
536	WERE	6,015	805	5,210	13.4	6,102	1,075		5,578	552
539	MKEC	678	58	620	8.6	388		142	265	19
540	MIPU	2,101	274	1,827	13.0	1,157			1,323	167
541	KACP	3,516	72	3,444	2.1	4,328	550		4,123	346
542	KACY	554	60	494	10.8	575			585	10
544	EMDE	1,177	125	1,053	10.6	1,123			1,157	34
545	INDN	322	2	320	0.7	217			240	23
546	SPRM	785	112	673	14.2	742			846	105
640	NPPD	3,660	267	3,393	7.3	3,119	8		3,348	238
645	OPPD	2,972	297	2,676	10.0	3,274			3,413	139
650	LES	803	2	802	0.2	263			299	37
							5,910			
	Import					4,807	4,807			
	Others		187							
	Total	52,125	5,419	46,893	198.8	56,923	10,716		50,506	4,299

Note: In the above table, the row identified as "Others" includes load shedding in areas EES (351) and WECC (999).

The frequency response of the load buses for the 20% generation loss scenario is shown in Figure 4-2. It can be seen that the frequency falls below first stage and second stages of UFLS setting (59.3 and 59.0 Hz respectively) and recovers to approximately 59.73 Hz.

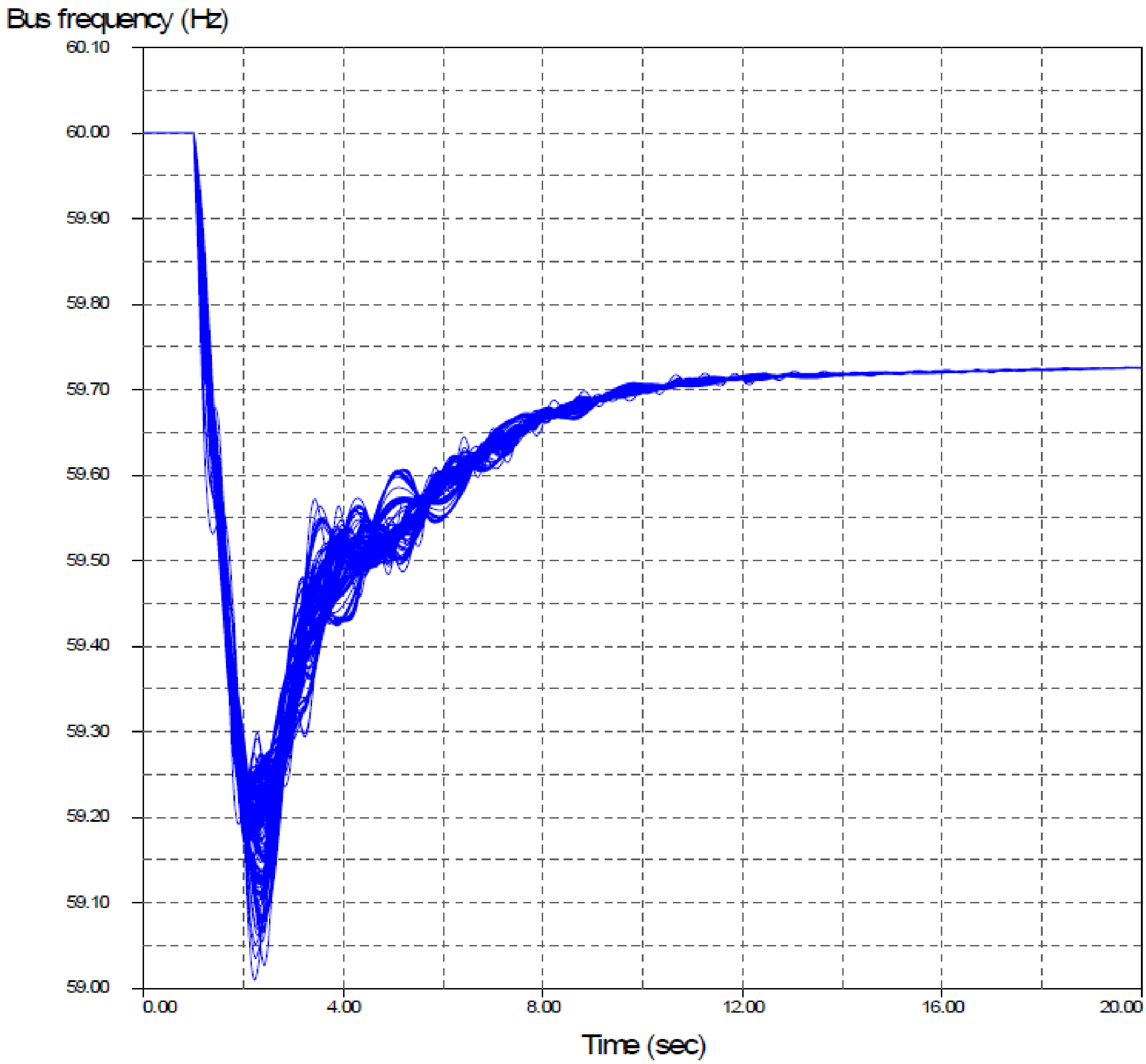

Figure 4-2: Load Bus Frequency Response for Scenario 2011_20%GS

Summary of the result for 20% generation loss scenario is shown in Table 4-8.

Table 4-8: Load Shedding Summary for Scenario ID 2011_20%GS

TSAT Results (MW)	
Load Shed by UFLS	5,232.15
Load Reduction due to Voltage & Frequency	845.32
Generation Shed	10,716.47
Spinning Reserve Used	4,299.16

4.3 Analysis of 30% Generation Loss

Selection of Simulation Scenario

The 30% generation loss scenario is similar to the 20% generation loss scenario described in the previous section with the exception of tripping of additional SPP generators to create the 30% generation loss. Table 4-9 lists the additional units that were disconnected in the dynamic simulations to achieve 30% generation loss.

Table 4-9: Scenario ID 2011_30%GS

Additional Generation Shed for Scenario 2011_30%						
No.	**Area#**	**Area Name**	**Bus #**	**Bus Name**	**Gen ID**	**MW**
1	502	CELE	501811	G1RODEMR 22.0	1	310.00
2			501910	G1 ACAD 18.0	1	200.00
3	515	SWPA	505452	NFK #1 1 13.8	1	10.00
4			505454	NFK #2 1 13.8	2	10.00
5			505462	BSH #1 1 13.8	1	36.60
6			505464	BSH #2 1 13.8	2	36.60
7			505466	BSH3&4 1 13.8	3	36.60
8			505466	BSH3&4 1 13.8	4	36.60
9			505468	BSH5&6 1 13.8	5	41.20
10			505468	BSH5&6 1 13.8	6	41.20
11			505470	BSH7&8 1 13.8	7	41.20
12			505470	BSH7&8 1 13.8	8	41.20
13			505476	TBR1&2 1 13.8	1	49.60
14			505476	TBR1&2 1 13.8	2	49.60
15			505478	TBR3&4 1 13.8	3	49.60
16			505478	TBR3&4 1 13.8	4	49.60
17	520	AEPW	506749	ESTGAS1 18.0	1	100.00
18			509392	ARSHILL3 18.0	G2	100.00
19			509409	WILKE3-1 22.0	1	200.00
20			511842	RSS1-1 24.0	1	407.87
21	523	GRDA	512686	SALINA 5 161.	1	37.03
22			512686	SALINA 5 161.	2	37.03
23			512686	SALINA 5 161.	3	37.03
24	524	OKGE	514859	MUSTNG4G 20.9	1	193.00
25			515226	MUSKOG6G 24.0	1	520.00
26	525	WFEC	520998	MORLND3 18.0	1	140.00
27			521110	ORME1 13.8	1	60.00
28	526	SWPS	523431	SIDRCH 2 69.0	1	20.00
29	527	OMPA	529251	OMPONCA2 69.0	3	11.07
30	531	MIDW	530555	COLBY 3 115.	01	5.02
31			530555	COLBY 3 115.	02	0.67
32			530595	SMOKY_WND 0.57	01	9.00

Additional Generation Shed for Scenario 2011_30%						
No.	Area#	Area Name	Bus #	Bus Name	Gen ID	MW
37	534	SUNC	531459	S2 GEN 1 13.8	2	90.00
38	536	WERE	532663	LEC U5 24.0	1	353.43
39	539	MKEC	539677	MULGREN1 13.8	3	91.00
40	540	MIPU	541165	S.HARP#1 13.8	1	105.00
41			541166	S.HARP#2 13.8	2	105.00
42	541	KACP	542952	MONTG1 1 22.0	1	120.00
43			542953	MONTG2 1 22.0	2	120.00
44	542	KACY	546698	QGEN2 1 15.0	1	124.37
45	544	EMDE	547648	OZD312 1 4.60	1	4.00
46			547648	OZD312 1 4.60	2	4.00
47			547648	OZD312 1 4.60	3	4.00
48			547648	OZD312 1 4.60	4	4.00
49			547658	S4G439 1 18.0	1	199.94
50	545	INDN	548806	BLUVLY 69.0	4	46.81
54	546	SPRM	549890	SWPS GEN#1 120.0	1	178.00
55	640	NPPD	640019	SHELDN1G 13.8	1	114.00
56			640020	SHELDN2G 13.8	2	129.00
57			640022	BPS GT1G 13.8	1	78.00
58			640154	CRETE G 34.5	1	15.70
59			641086	EGY CTRG 13.8	1	84.00
60			642067	PLATTE1G 13.8	1	104.40
61	645	OPPD	645001	FT CAL1G 22.0	1	505.00
62	650	LES	650092	ROKEBY2G 13.8	2	62.00
					Total:	5,559.03

Simulation Results

The result of time domain simulation runs for 30% generation loss scenario is summarized in Table 4-10.

Table 4-10: Load Shedding Summary by Area For Scenario ID 2011s_30%GS

Area	Name	Initial Load (MW)	Load Shed (MW)	Final Load (MW)	Load Shed (%)	Initial Gen. (MW)	Gen. Shed		Final Gen (MW)	Spinning Reserve Used (MW)
							Scheduled (MW)	UFLS (MW)		
502	CELE	1,852	348	1,504	18.8	2,895	528		2,554	187
503	LAFA	485	7	479	1.4	223	100		132	9
504	LEPA	61	0	61	0.0	47	10		37	0
515	SWPA	899	39	860	4.3	1,941	970		1,048	77
520	AEPW	10,135	1,953	8,182	19.3	9,460	2,308		7,354	202
523	GRDA	970	297	673	30.6	1,121	111		1,046	36
524	OKGE	6,325	1,855	4,470	29.3	7,320	1,770		5,859	309
525	WFEC	1,383	342	1,041	24.7	1,204	200		1,052	48
526	SWPS	5,937	1,362	4,575	22.9	5,896	1,030		5,078	212
527	OMPA	666	119	548	17.8	56	11		46	2
531	MIDW	376	53	323	14.2	125	15		110	0
534	SUNC	452	95	357	21.0	544	90		481	26
536	WERE	6,015	1,580	4,435	26.3	6,102	1,428		5,001	328
539	MKEC	678	176	503	25.9	388	91	142	163	8
540	MIPU	2,101	811	1,291	38.6	1,157	210		1,033	87
541	KACP	3,516	569	2,947	16.2	4,328	790		3,745	208
542	KACY	554	173	381	31.3	575	124		455	4
544	EMDE	1,177	229	949	19.4	1,123	216		924	18
545	INDN	322	3	319	1.1	217	47		182	12
546	SPRM	785	187	598	23.9	742	178		613	49
640	NPPD	3,660	777	2,882	21.2	3,119	533		2,732	146
645	OPPD	2,972	781	2,192	26.3	3,274	505		2,863	95
650	LES	803	3	800	0.4	263	62		224	23
							11,469			
	Import					4,807	4,807			
	Others		294							
	Total	52,125	12,052	40,367	434.8	56,923	16,276		42,733	2,085

Note: In the above table, the row identified as "Others" includes load curtailment in areas EES (351) and WECC (999).

The frequency response of the load buses for the 30% generation loss scenario is shown in Figure 4-3. It can be seen that the frequency falls approximately to 58.5 Hz activating the third stage of UFLS and is stabilized to approximately 59.75 Hz.

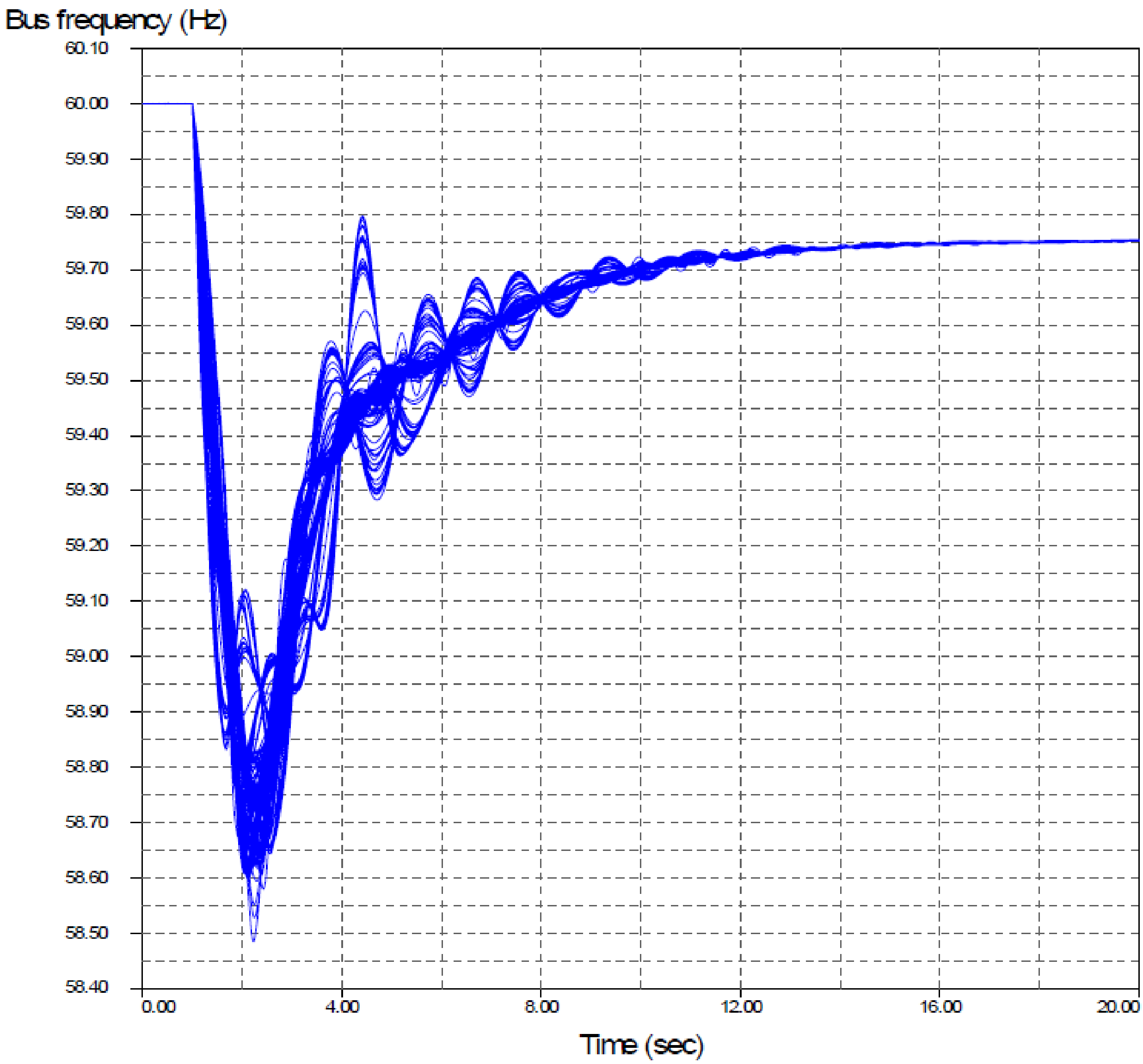

Figure 4-3: Load Bus Frequency Response for Scenario 2011_30%GS

Summary of the results for the 30% generation loss scenarios are shown in Table 4-11.

Table 4-11: Load Shedding Summary for Scenario ID 2011_30%GS

TSAT Results (MW)	
Load Shed by UFLS	11,757.87
Load Reduction due to Voltage & Frequency	393.49
Generation Shed	16,275.63
Spinning Reserve Used	2,085.14

30% Generation Loss Scenario Assuming 10% Over Shedding

Since the exact amount of load available for the UFLS scheme is practically difficult to estimate, SPP is concerned that an over-frequency situation, due to over shedding, may arise under the worst condition of mismatch between load and generation (e.g. 30% generation loss). To address this concern, it was decided to repeat the 30% generation loss scenario, similar to the previous section, with the exception of simulating additional load shedding by suddenly ramping down the load by 10%. Figure 4-4 shows the frequency of the monitored SPP generators for the 30% generation loss scenario for 2011 basecase with an additional 10% load shed. The maximum frequency reached is approximately 60.40 Hz. This frequency overshoot is not expected to activate any generator over-speed protection scheme.

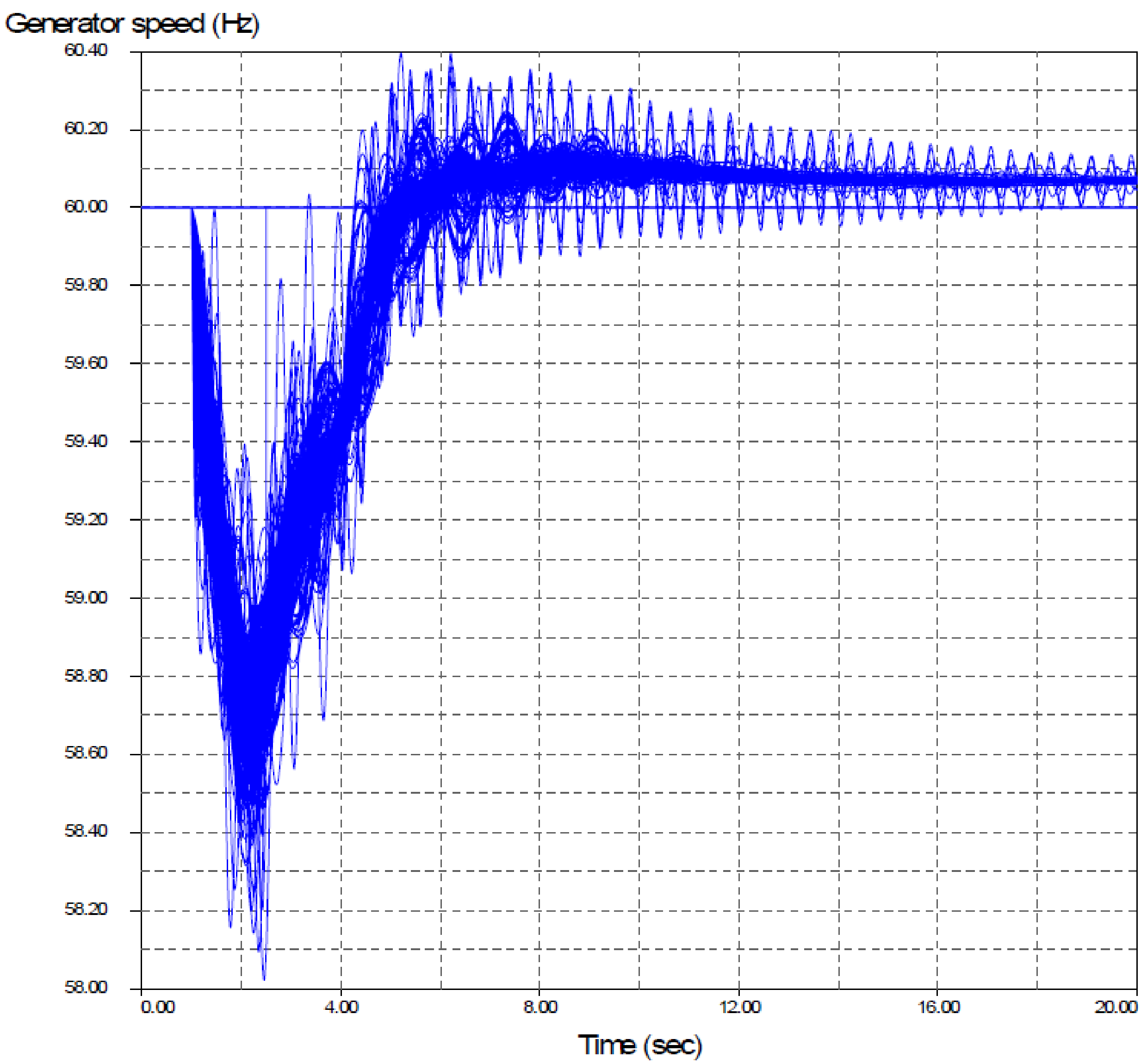

Figure 4-4: Generator Frequency for Scenario 2011_30%GS with Additional 10% Load Shedding

30% Generation Loss Scenario Assuming 15% Over Shedding

A similar simulation as described in the previous section was carried out but assuming 15% over-shedding[5]. In this case, the maximum over-frequency is approximately 60.71 Hz depicted in Figure 4-5. It is not expected that such a frequency could cause generator over-speed protection to trip any units; however, it is recommended that SPP members investigate if any of their units have over-speed protections with settings close to the observed over-frequency condition.

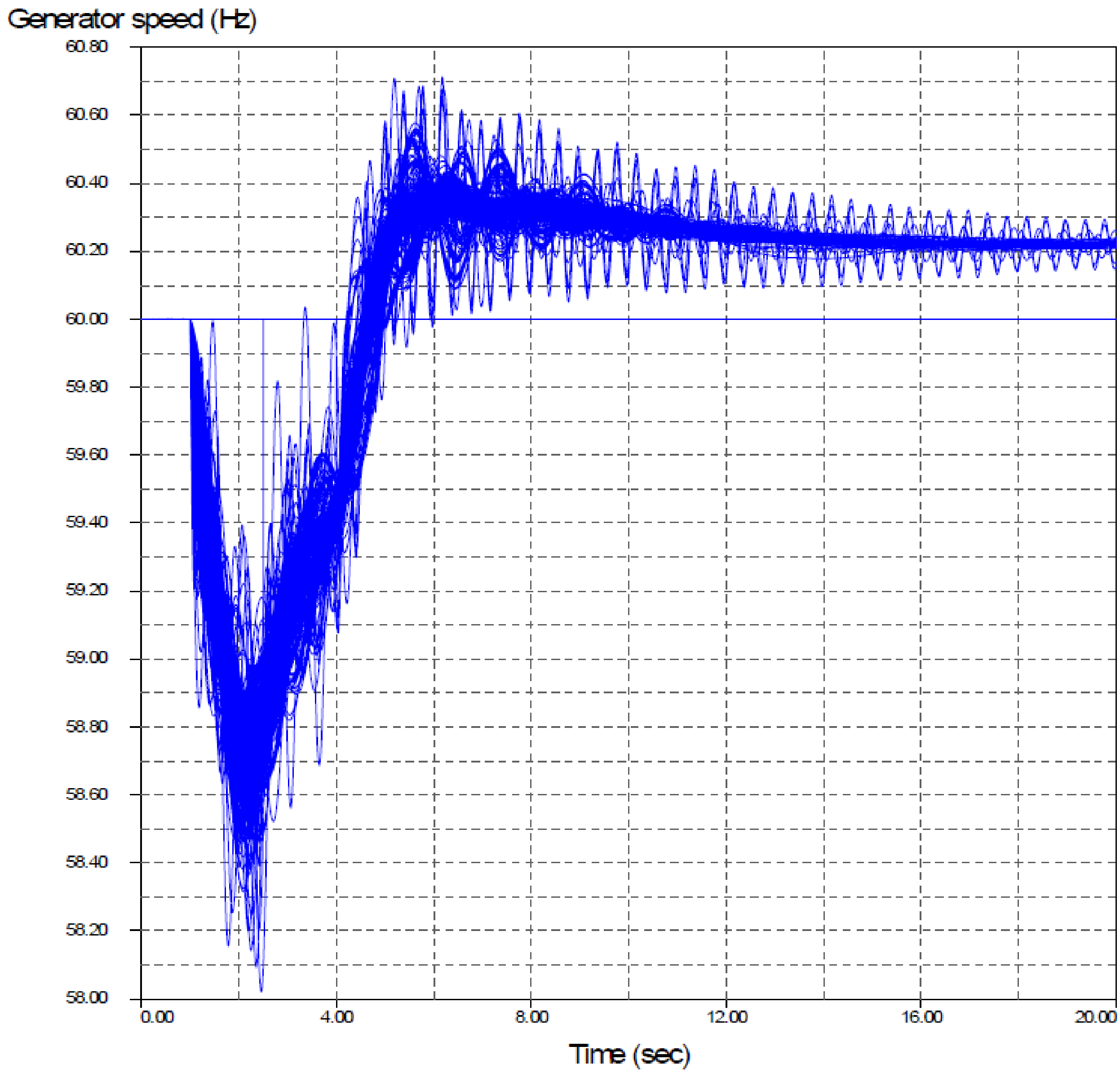

Figure 4-5: Generator Frequency for Scenario 2011_30%GS with Additional 15% Load Shedding

[5] In addition to the list of the disconnected generators under 30%generator loss scenario, generator 529252, ID:1 with 29.7 MW output was also disconnected for this study to improve system-wide dynamical performance.

30% Generation Loss Scenario with 45% SPP-wide load Shedding

In order to further investigate system performance subjected to excessive load shed, the effect of 30% generation loss[6] with 45% system-wide load shed throughout SPP is investigated[7]. The load shed is implemented by reducing the SPP load to -45% of its value over a period of 0.1 seconds. The simulation results indicated that the maximum over-frequency is approximately 61.5 Hz as depicted in Figure 4-6. It is not expected that this frequency will cause generator over-speed protection to trip any units.

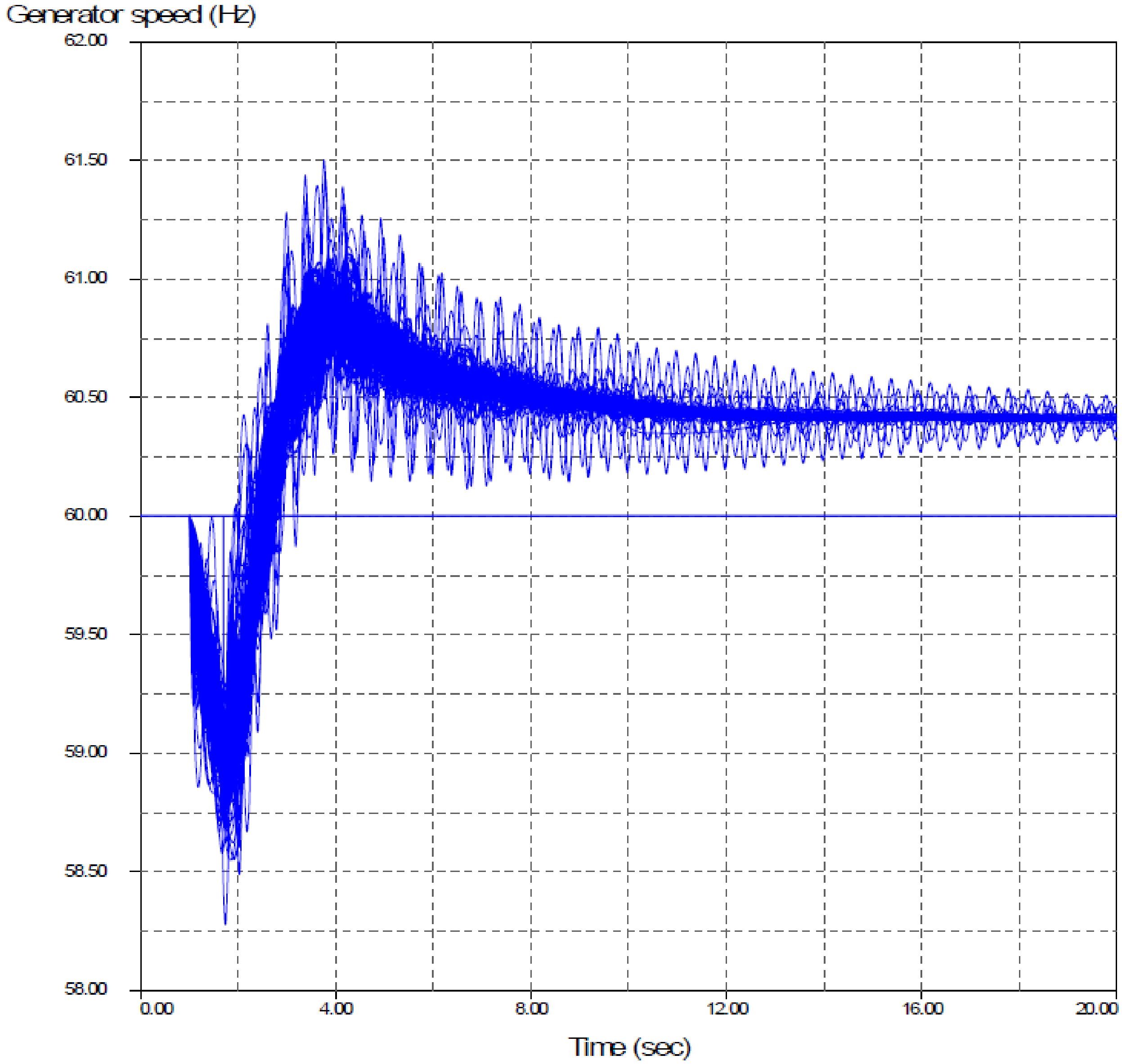

Figure 4-6: Generator Frequency for Scenario 2011_30%GS with 45% SPP Load Shedding

[6] In addition to the list of the disconnected generators; i.e. 30% generator loss scenario, generator located at bus 529252, ID:1 with 29.7MW output and generator located at bus 650001, ID:1 with 23 MW were also disconnected.
[7] For sake of this scenario the effect of UFLS relays were not considered

Study of under-voltage inhibit setting on UFLS scheme

In order to determine the effect of under-voltage inhibit on the UFLS scheme operation, it is required to identify UFLS relays with bus voltages with equal or less than inhibit threshold value of 85%. For this purpose, bus voltages of the UFLS relays that operated during 30% generation deficiency scenario were monitored and relays with bus voltages equal or below the inhibit value of 0.85 pu prior to relay operation were identified.

The simulation progress report indicated that a total of 907 UFLS relays operated during 30% gen loss scenario. For these relays their bus voltages prior to the moment that they operated were monitored, and buses with voltage magnitudes equal or below the inhibit threshold were identified. These buses were reported in the following table.

Table 4-12: UFLS relays affected by voltage inhibit

AREA	Bus		Pre-operation Voltage (pu)	Affected Load (MW)	Note
	#	Name			
515 SWPA	505408	KENNETT2 69.0	0.00	38.5	Bus voltage was reduced to zero as a result of generator shed.
544 EMDE	547489	BRN413 5 161.	0.77	25.8	
	547497	RVS438 5 161.	0.82	21.5	
	547587	STR370 2 69.0	0.84	5.2	
	547604	BHJ415 2 69.0	0.81	11.0	
			Total:	102.0	

Note: Bus 505408 voltage was dropped to zero at 1.0 seconds, before the first UFLS relay operation at 1.484 seconds; part of 30% gen shed.

The voltages for buses 547489 (red), 547497 (blue), 547587 (green), 547604 (brown) are provided below.

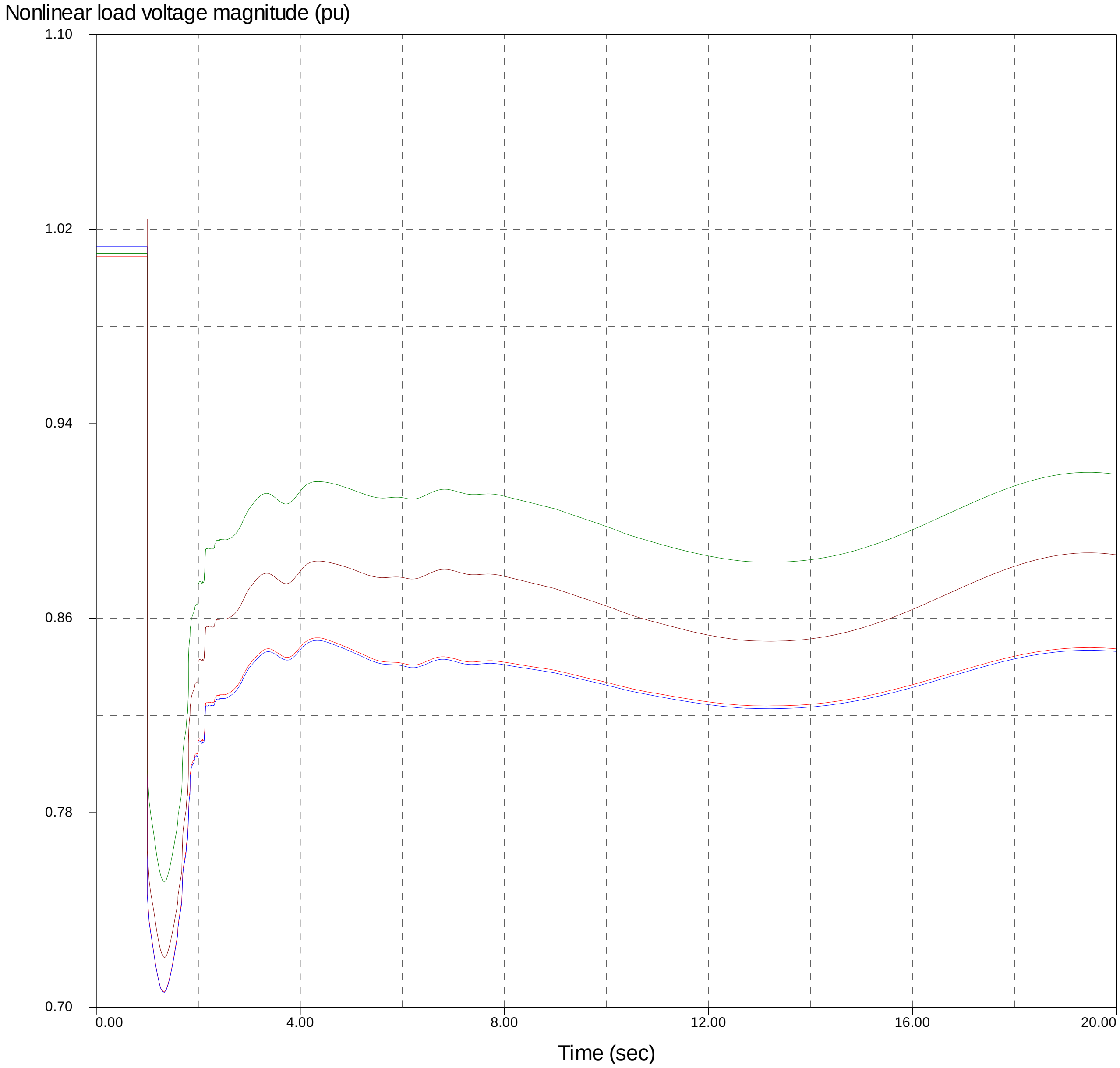

Figure 4-7: Inhibit Bus Voltages for Scenario 2011_30%GS

The above results indicated that the load shedding scheme that could be affected by the UFLS inhibit function is 102 MW. This amount accounts for less than 1% of the load dropped by UFLS scheme (11,758 MW). Therefore, as confirmed by simulation, under-voltage inhibit setting equal to 85% and below has negligible impact on the SPP established UFLS program.

Study of V/Hz (Magnetic flux)

As a part of UFLS evaluation, V/Hz for all SPP generators at generator terminal bus and/or generator step-up (GSU) transformer high-side bus was studied. This study is performed to assess generators and transformers magnetic flux during 30% generation loss scenario. The actual magnitude of magnetic flux in generator stator or transformer core is difficult to measure, however it can be quantified in terms of per unit V/Hz, since the operating magnetic flux in electric machineries is proportional to the ratio of the operating voltage to the electrical frequency. Therefore, V/Hz provides a measure of generator stator and transformer core magnetic flux. Excessive magnetic flux in transformer or generator results in thermal damages to generator and GSU transformer. These damages are typically cumulative. These damages include, but are not limited to, generator stator and GSU transformer core damage, and degradation of insulation material. Excessive magnetic flux may even cause unwanted operation of protection system. The objective of study is to identify generator terminal or GSU transformer high-side buses for which V/Hz exceeds stipulated values of 1.18 pu for longer than two seconds cumulatively, or 1.1 pu for longer than 45 seconds cumulatively for the simulated event of 30% generation loss scenario.

Following a preliminary review of the generators' V/Hz, the following observations were made.

- Generator terminal bus 640090 V/Hz exceeded 1.18 pu prior to the 30% generation loss simulated event.
- Generator terminal buses 514897, 5244485 and 541151 V/Hz exceeded 1.1 pu prior to the 30% generation loss event and as the system reaches steady state following the simulated event.

The details pertaining to these generators are summarized below. The V/Hz in per unit at each generator terminals prior to the simulated event and at steady state after the simulated event are provided. The generator terminal voltage and GSU transformer high voltage side in per unit prior to the simulated event are also provided.

Table 4-13: Generators with large V/Hz

Area	Bus no.	Bus name	Generator		V/Hz (pu)		Voltage (pu)		Note
			ID	Base MVA	Initial	Final	GSU Xfrm HV	Gen. terminal	
524 OKGE	514897	SMITH 1S 13.8	1	55.5	1.12	1.12	1.02	1.12	Generator terminal voltage is initially 1.12 pu. The three-winding GSU transformer has relatively large tertiary impedance.
526 SPS	524485	CAPROCK_WND134.5	DA	40.4	1.15	1.17	1.03	1.16	Synchronous condenser.
540 MIPU	541151	SIBLEY#3 22.0	3	451	1.15	1.15	1.02	1.15	Generator terminal voltage is initially 1.15 pu. The GSU transformer impedance is substantially large (24% on generator basis).
640 NPPD	640090	BROKENBG 69.0	1	1	1.23	1.03	1.04	1.23	Generator terminal voltage is initially 1.23 pu. Suspicious generator base MVA; 1MVA? The powerflow results indicate that generator injects 8.3 MW

Review of the above information indicated that the observed initial high V/Hz values for the above mentioned fours generators are contributed to the generator terminal voltages exceeding 1.1 pu prior to the simulated event.[8] In addition, inaccuracy of system data, such as generator base MVA or GSU transformer impedance, could have contributed to the observed generator terminal voltage magnitudes. Since the observed V/Hz for these generators is partially contributed to inaccurate data, no reasonable conclusion can be made from the observed responses of these generators. Thus, these four generators were excluded from V/Hz study.

The plots of generator V/Hz are provided in Figure 4-8. As shown in this figure no generator V/Hz response exceeds 1.18 pu; however, a number of generators' V/Hz response exceed 1.1 pu; however, the cumulative times for these generators are reasonably below 45 seconds.

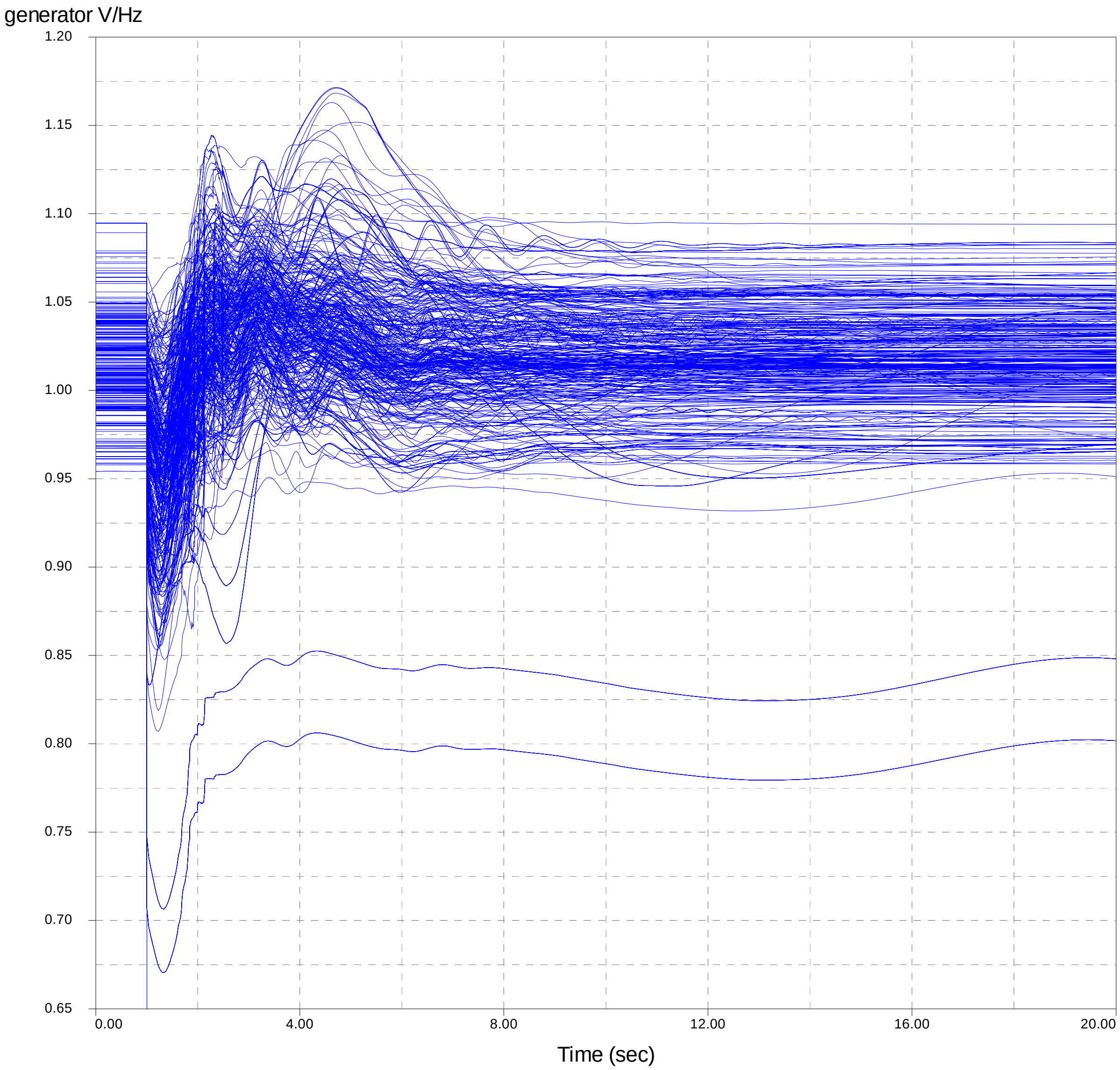

Figure 4-8: Generators V/Hz for 30%_GS

[8] It was noticed that generators 514897, 524485 and 541151AVRs were set to control GSU high voltage bus magnitude.

Study of Effect of Delay in Operation of (UFLS) Relays

In order to study load shedding sensitivity versus relay pickup time setting, the 30% generation drop scenario was simulated with UFLS scheme relays' pickup time adjusted to 30 and 40 cycles, and breaker times adjusted to 6 cycles. In addition all SPP generators were equipped with under-frequency protection scheme. This scheme was adjusted according to PRC-006-SPP-01 characteristic curve.[9] This study develops an insight into the UFLS scheme delay sensitivity by investigating the effect of system-wide UFLS trip time setting. Generally speaking, under-frequency protection at the generator must not operate for disturbances successfully managed by UFLS scheme. Thus the number of the disconnected generator provides an indication UFLS scheme sensitivity to relay pickup time.

30 Cycles Delay

The simulation results for 30% generation loss event with UFLS scheme relays' pickup time adjusted to 30 cycles and breaker times adjusted to 6 cycles, and generators equipped with under-frequency protection are provided below. As the results indicated, the system remains reasonably secure.

[9] This characteristic was implemented using a UDM (user-defined model) for each generator. The implementation is based on monitoring of weighted accumulated time for generator frequencies below 59.3 Hz. This accumulated time is reset for generator frequency above 59.3 Hz. The generator under-frequency protection scheme disconnects the generator once the generator frequency versus weighted accumulated time breaches the under-frequency characteristic requirement. The accumulated time is updated and adjusted by a weighting factor. This weighting factor is a function of generator speed and is adjusted based on under-frequency characteristic requirement.

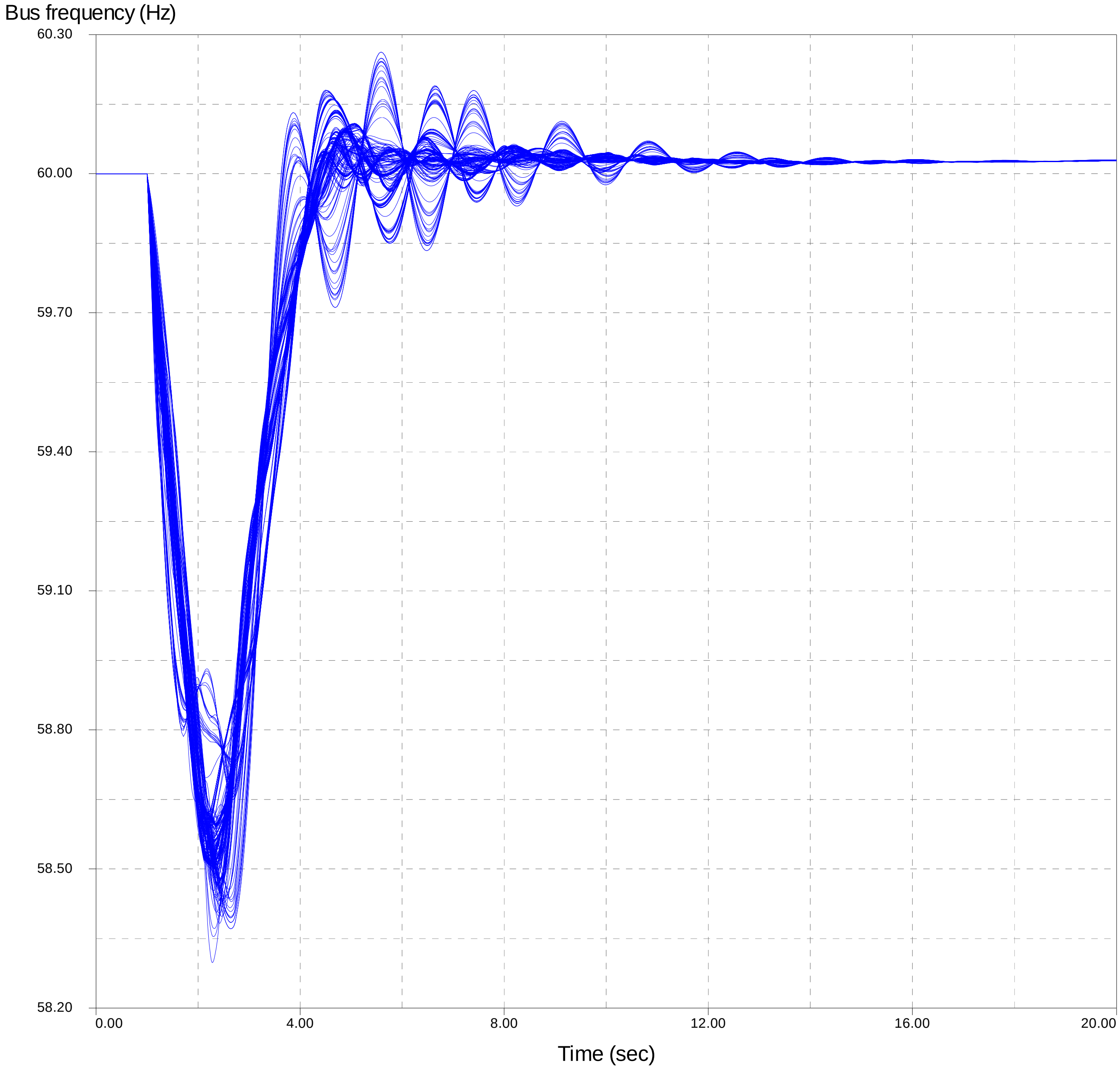

Figure 4-9: Load bus Frequency for Scenario 2011_30%GS with 30 cycles delay

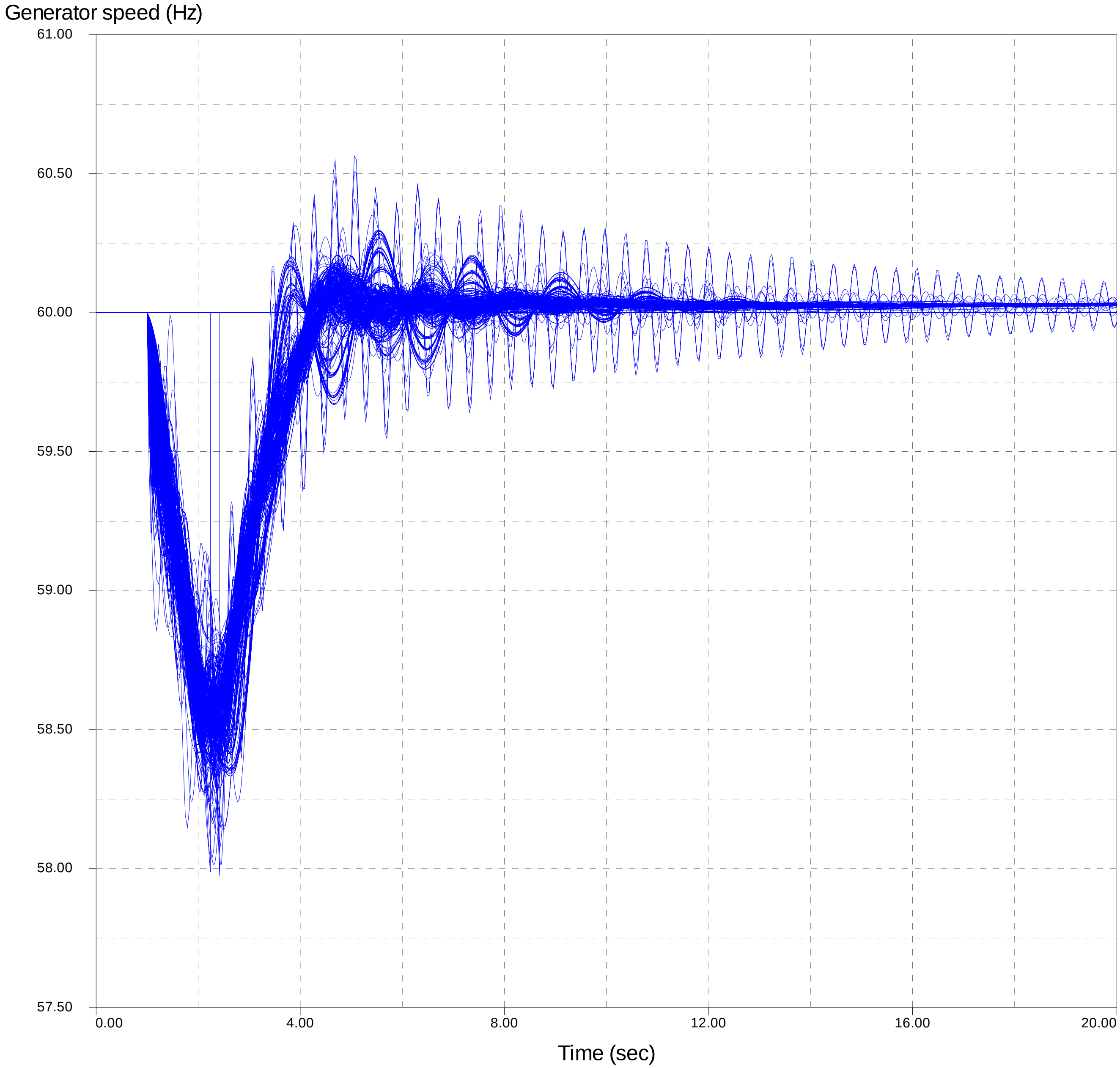

Figure 4-10: Generator Frequency for Scenario 2011_30%GS with 30 cycles delay

The simulation results indicated that the generator under-frequency protection disconnected two generators (640026, 659134).

Table 4-14: Generators tripped by under-frequency requirement for 30-cycle delay

Generation Shed during 30-cycles delay scenario						
No.	**Area#**	**Area Name**	**Bus #**	**Bus Name**	**Gen ID**	**MW**
1	640	NPPD	640026	AINSWD1W 0.60	1	12.00
2			659134	SIDNEY 4 230.	1	20.00
					Total:	32.00

In addition it was observed that two generators performance became relatively close to under-frequency requirement (640016, 640401). In order to develop a better understanding, a comparative study between a tripped generator (640026) and a generator with close to tripping performance (640016) was conducted. The results of the comparative study are provided in Figure 4-11. The frequency speed response for generators 640016 (red) and 640026 (blue) are depicted below.

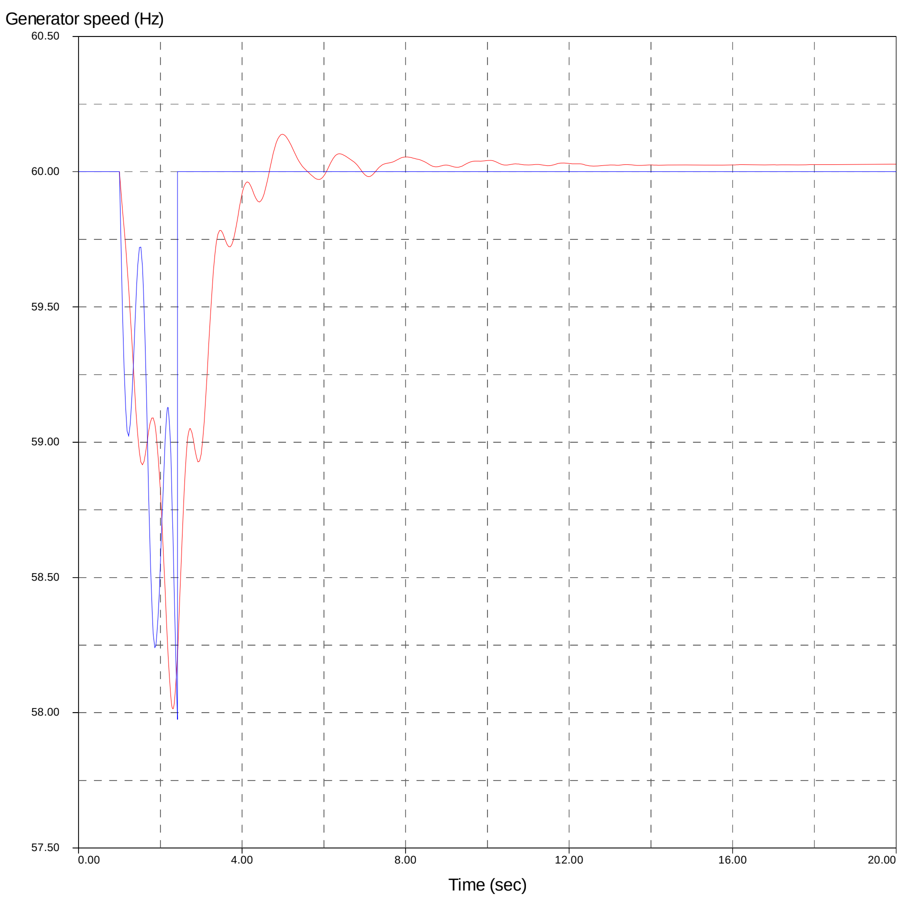

Figure 4-11: Generators 640016 and 640026 Frequency responses for 30 Cycles delay

The plots of generator speed versus weighted accumulated time for the two generators are provided in Figure 4-12. The generator under-frequency requirement curve is also shown overlaid in black. As shown in this figure, generator 640026 (blue) frequency response intersects with generator under-frequency protection curve; however, generator 640016 (red) frequency response does not intersect with the generator under-frequency protection curve. As under-frequency requirement were implemented for all SPP generators, generator 640026 was disconnected at the moment its frequency response intersects the under-frequency requirement curve.

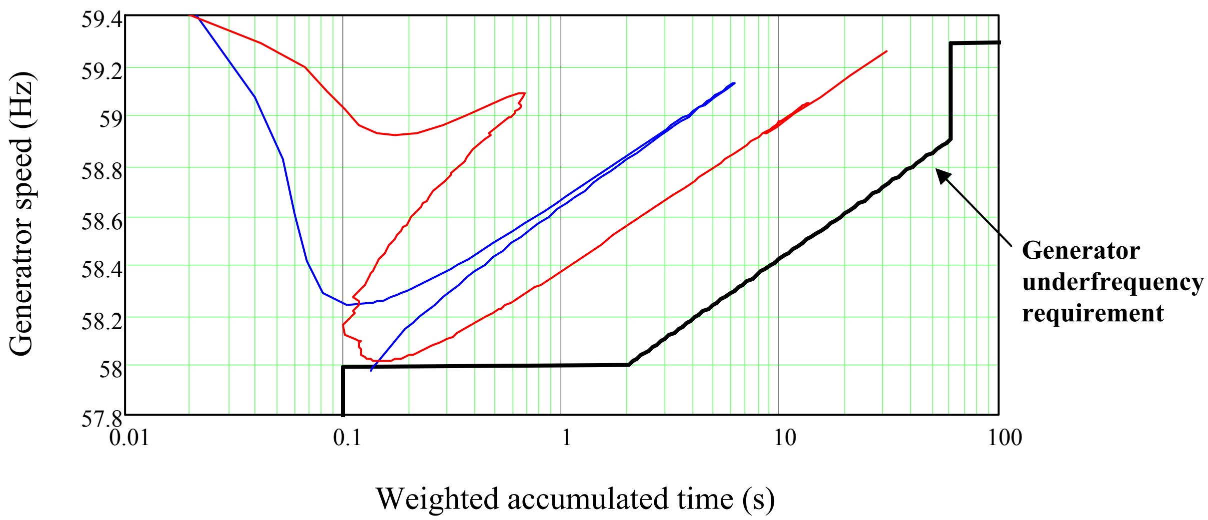

Figure 4-12: Generators 640016 and 640026 Under-frequency responses for 30 Cycles delay

As a part of UFLS evaluation, V/Hz for all SPP generators for this scenario was studied. The objective of this was to identify generators for which V/Hz exceeds 1.18 pu for longer than two seconds cumulatively, or exceeds 1.1 pu for longer than 45 seconds cumulatively for simulated event of 30% generation scenario. The plots of generator V/Hz are depicted below. As shown in this figure no generator V/Hz exceeds 1.18 pu; however a number of generators V/Hz exceeded 1.1 pu.

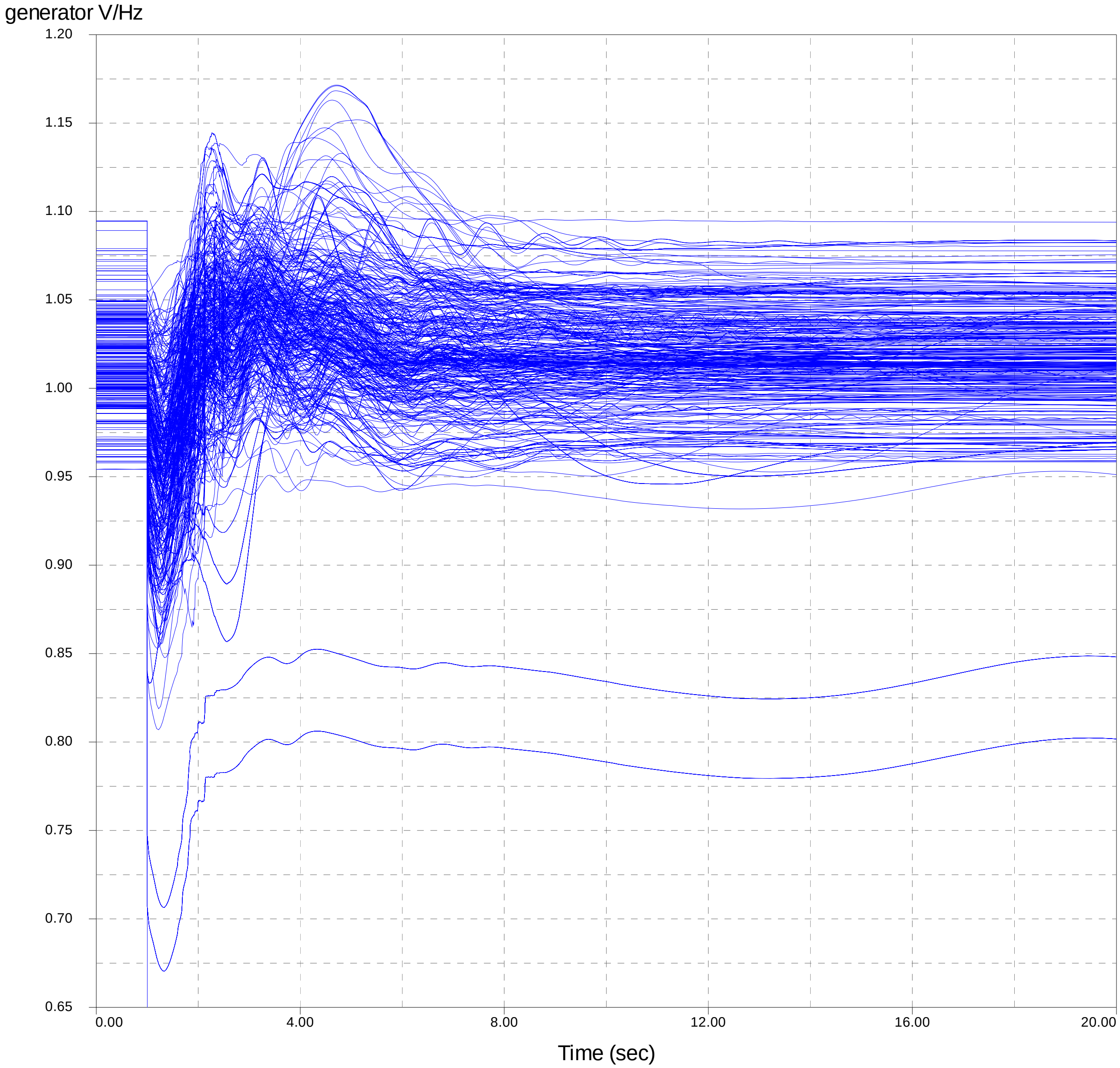

Figure 4-13: Generators V/Hz for 30%_GS with 30 Cycles Delay

The simulation results indicated that 33 generators V/Hz response exceeded 1.1 pu; however, the calculated cumulative times for generators' V/Hz are considerably less than 45 seconds. The maximum calculated cumulative time was 3.8 seconds for generator 506754.

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40 Cycles Delay

The simulation results for 30% generation loss event with UFLS scheme relays' pickup time adjusted to 40 cycles and breaker times adjusted to 6 cycles, and generators equipped with under-frequency protection are provided below. As the results indicated, the system remains reasonably secure.

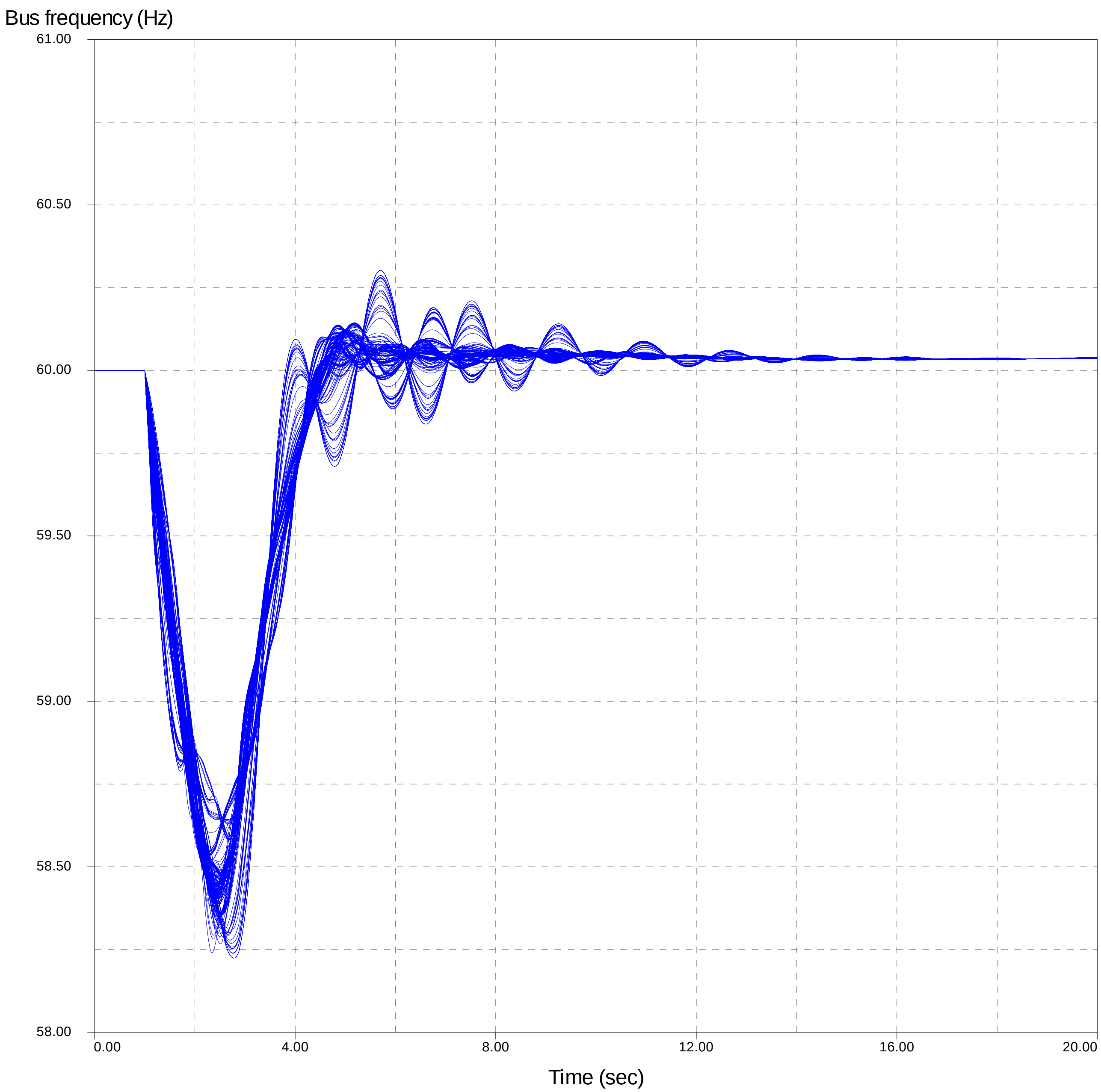

Figure 4-14: Load Buses Frequency for Scenario 2011_30%GS with 40 cycles delay

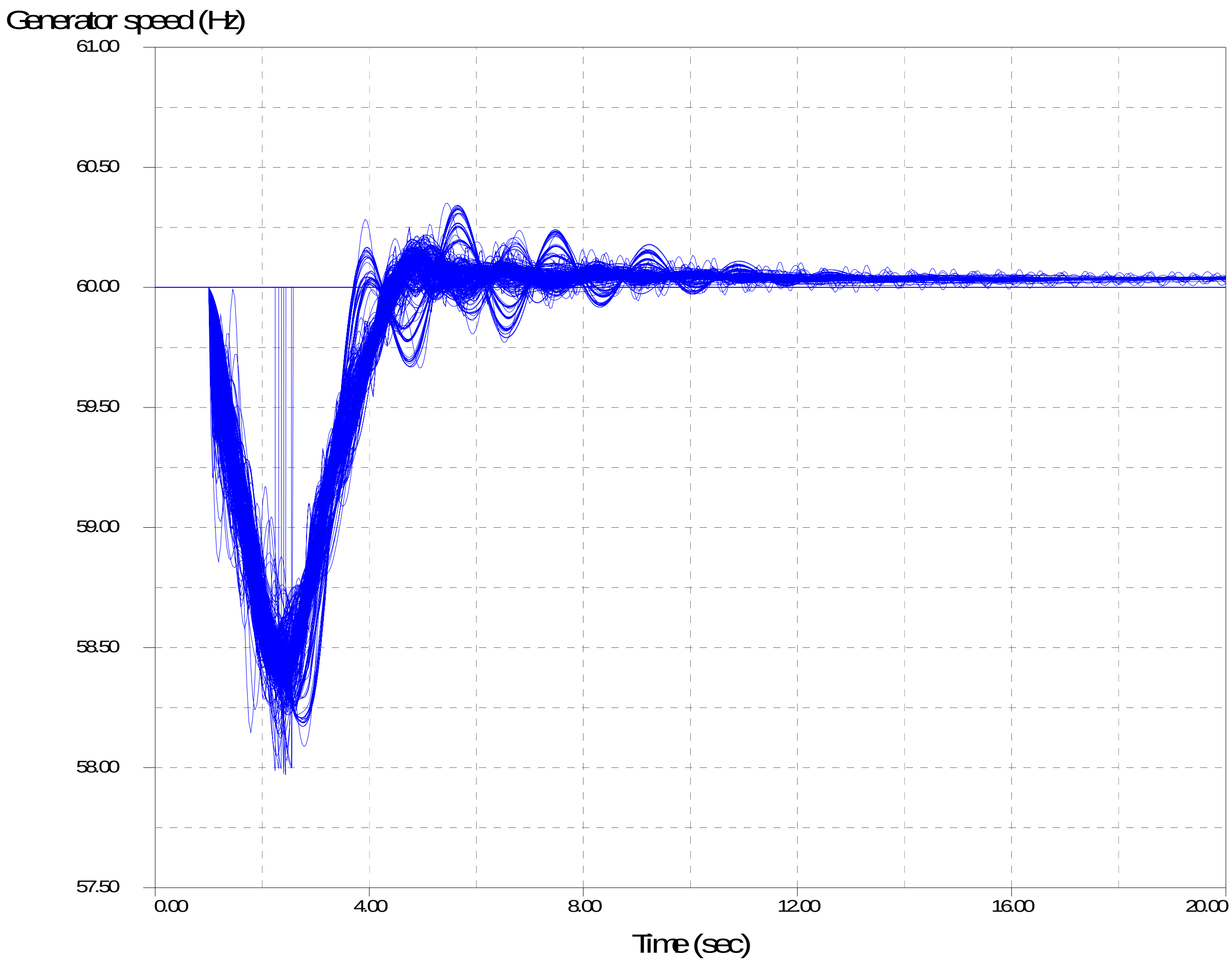

Figure 4-15: Generator Frequency for Scenario 2011_30%GS with 40 cycles delay

The simulation results indicated that the generator under-frequency protection disconnected seven generators (531461, 531462, 640016. 640026, 640401, 640418, 659134).

Table 4-15: Generators tripped by under-frequency requirement for 40-cycle delay

Generation Shed during 40-cycles delay scenario						
No.	**Area#**	**Area Name**	**Bus #**	**Bus Name**	**Gen ID**	**MW**
1	534	SUNC	531461	S4 GEN 1 13.2	4	48.00
2			531462	S4 GEN 1 13.2	5	48.00
3	640	NPPD	640016	KINGSLYG 13.8	1	33.00
4			640026	AINSWD1W 0.60	1	12.00
5			640401	W.POINTG 34.5	1	7.40
6			640418	ELKRDG1W 34.5	1	16.00
7			659134	SIDNEY 4 230.	1	20.00
					Total:	184.40

As a part of UFLS evaluation, V/Hz for all SPP generators for this scenario was studied. The objective of this was to identify generators for which V/Hz exceeds 1.18 pu for longer than two seconds cumulatively, or exceeds 1.1 pu for longer than 45 seconds cumulatively for simulated event of 30% generation scenario. The plots of generator V/Hz are depicted below. As shown in this figure no generator V/Hz exceeds 1.18 pu; however a number of generators V/Hz exceeded 1.1 pu.

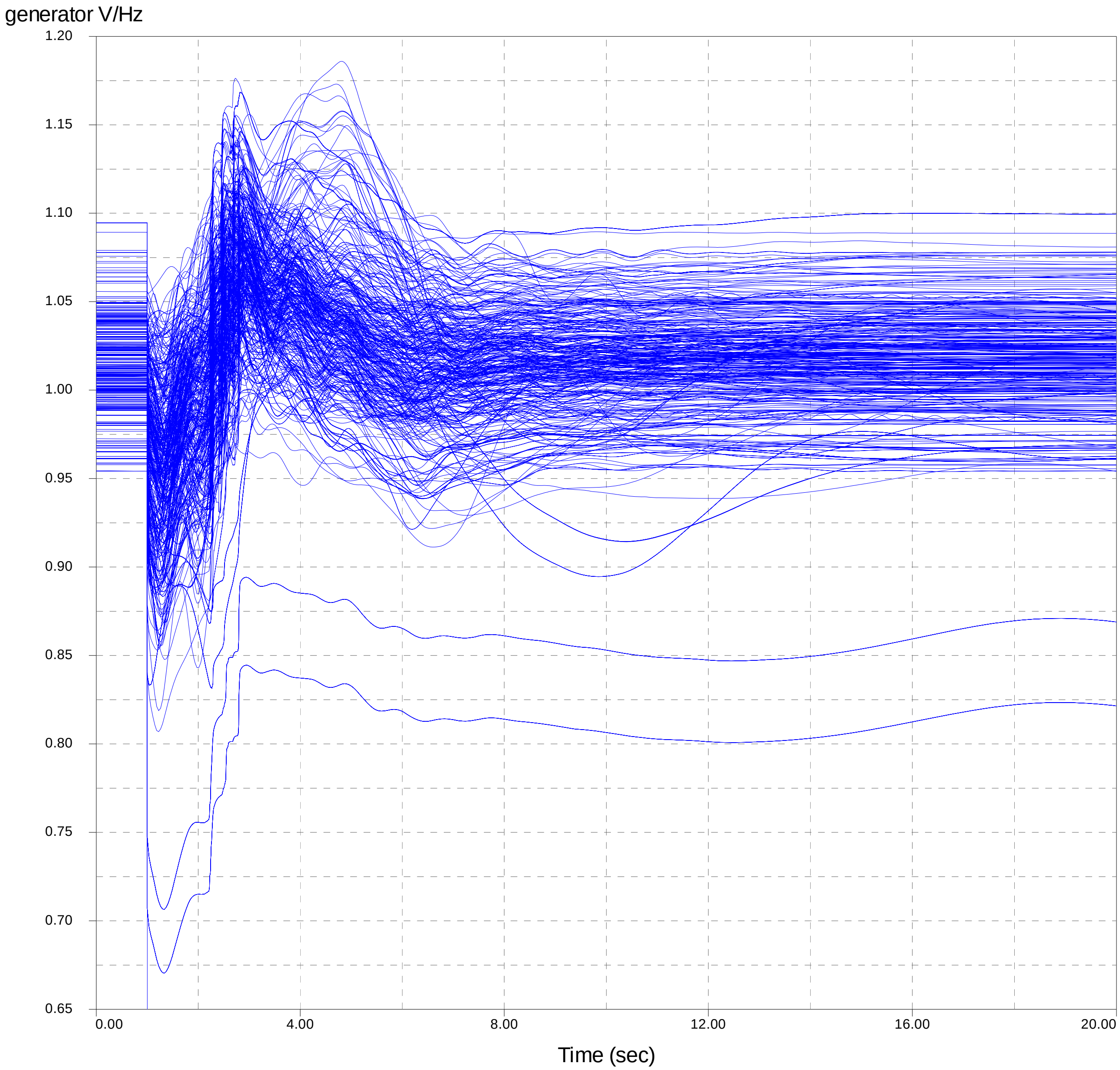

Figure 4-16: Generators V/Hz for 30%_GS with 40 Cycles Delay

The simulation results indicated that 49 generators measured V/Hz exceeds 1.1 pu for more than a second; however, the calculated cumulative times for generators' V/Hz are considerably less than 45 seconds.

It was noted as the system transients following the simulated event settles and system response reaches a steady state, the terminal voltage of five generators connected to bus number 533582 practically becomes 1.1 pu (in fact the terminal voltage becomes ~1.098 pu). Therefore, the V/Hz for these generators become close to the stipulated value of 1.1 pu at steady state.

Cursory comparison between generator frequency plots for 40 cycle delay versus 30 cycle delay indicates less generator oscillation for 40 cycle delay. This observation is believed to be mainly contributed to system-wide implementation of generator under-frequency protection, as five additional generators were disconnected under 40 cycles delay case.

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5 Conclusions & Recommendations

In this study, the UFLS program of SPP was evaluated. As part of NERC/SPP compliance program requirements, SPP members compiled and submitted their load shedding relay data. SPP members have maintained and updated their UFLS relay data every five years (the last update was reported in 2006). The review of relay data shows that the relay settings, load shedding amount in each stage of load shedding, and time delays adhere to the NERC/SPP requirements. The simulated events also indicated that the UFLS program is reasonably coordinated with generation protection[10], and is reasonably immune to UFLS relay under-voltage inhibit setting of 85% and below. In order to study sensitivity of UFLS program to trip time setting, the effect of a universal relay pickup time setting for UFLS program was studied. The simulation results for 30% generation loss event with UFLS scheme relays' pickup time adjusted up to 40 cycles while all generators equipped with under-frequency protection indicated that the system remains reasonably secure following the operation of established UFLS program.[11] Additional generator protective concerns such as excessive magnetic flux (V/Hz) and generator under-frequency requirement were also investigated, and it was determined that generators V/Hz performance was within stipulated range.

The following outlines stipulate major findings that substantiate SPP's compliance to the UFLS program:

- Review of the SPP relay data reveals that SPP and its members closely adhere to a coordinated load shedding scheme. Additionally, the study indicates that there is no unusual protection requirement that necessitate special coordination with other NERC regions.

- Review of the SPP relay data and dynamic simulation of severe generation/load imbalance scenarios, showed SPP and its members closely adhere to a coordinated (amount and frequency set-points) load shedding scheme to arrest frequency decline. The coordinated UFLS program does not warrant minimization of load shedding; however, the study results do not appear to indicate that excessive load shedding has taken place with existing UFLS program. Regarding system restoration, the only comment that can be made is that the result did not show any loss of tie lines (within SPP) during frequency decline that could prolong restoration progress.

- The SPP's UFLS assessment using a time-domain simulation program is being conducted periodically (the last evaluation was performed five years ago in year 2006).

- The relay data and simulation results showed SPP members have a generally[12] consistent (amount, frequency set-points and relay and breaker operating time)

[10] Based on the generator under frequency relay data in database.
[11] Additional load was disconnected compared to 30% gen loss scenario.
[12] Even though there are instances that relay operating times are not consistent possibly due to relay types (e.g. electromechanical versus solid state) but this should not be interpreted as having an inconsistent program.

UFLS program.

- The SPP members have defined a protection relay data in MS Excel format. The SPP members have compiled necessary information for different relay types. This data has been used effectively in the present study. SPP members should maintain this data and update it annually.

- The result of time-domain simulations in this study proved that the SPP UFLS program is indeed effective in arresting frequency decline under conditions of severe mismatch between load and generation.

- As part of NERC compliance SPP should maintain and update the UFLS relay data annually.

- As part of NERC compliance SPP should conduct a study, similar to the one reported herein, every five years in order to provide evidence that its UFLS program is effective to cope with system changes.

Recommendations

Based on the findings of this study, the following recommendations are provided,

(a) Review of SPP relay settings indicated that these settings are satisfactory throughout the SPP system and adhere to NERC and SPP UFLS standards. However some members have relatively low percentage (≤ 20%) of UFLS armed loads. The areas LAFA, LEPA, SWPA, MIDW, INDN, NPPD and LES have UFLS armed load ratios that are substantially lower than 30%. As stipulated by SPP UFLS standard 7.3.1.3.a., members must be ready to shed 30% of their load by UFLS relays.

(b) It is recommended that SPP members investigate if any of their generating units have over-speed protections with settings around 61.5 Hz. This is the highest over frequency observed in the simulation of the server generation loss and 45% load shedding scenario. The observed duration for this frequency, 61.5 Hz, was substantially shorter than the maximum allowable duration of 10 seconds stipulated by over-frequency requirement curve.

This report is prepared by standard of care and based on the information supplied by SPP for and during the course of this study.

6 References

[1] NERC Reliability Standards for the Bulk Electric Systems of North America, February 7, 2006.

[2] Southwest Power Pool Criteria, October 2004.

[3] C. Concordia, L. Fink, G. Poullikkas, “Load Shedding on an Isolated System”, IEEE Transaction on Power Systems, Vol. 10, No. 3, August 1995

[4] Mukesh Nagpal, Ali Moshref, et al, “Dynamic Simulations Optimize Application of an Under Frequency Load Shedding Scheme”, Presented to the 24th Annual Western Protective relaying Conference, Spokane, WA, October, 1997

[5] D. W. Smaha, C. R. Rowland, and J. W. Pope, “Coordination of Load Conservation with Turbine-Generator Under frequency Protection,” IEEE Transactions on Power Apparatus and Systems, Vol. PAS-99, No. 3, pp. 1137–1150, May/June 1980.

[6] C. W. Taylor, F. R. Nassief, and R. L. Cresap, “Northwest Power Pool Transient Stability and Load Shedding Controls for Generation–Load Imbalances”, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 7, pp. 3486–3495, July 1981.

[7] K. L. Hicks, “Hybrid Load Shedding is Frequency Based”, IEEE Spectrum, pp. 52–56, February 1983.

7 Appendix A – NERC UFLS Standards

As of April 1st, 2005 the NERC Reliability Standards superseded the NERC Planning Standards. The following Reliability Standards (PRC-006 to PRC-009) apply to UFLS programs and have been extracted from the NERC document "Reliability Standards for the Bulk Electric Systems of North America" dated February 7, 2006 [1].

Standard PRC-006-0 — Development and Documentation of Regional UFLS Programs

Effective Date: April 1, 2005

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.

Standard PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements
Effective Date: April 1, 2005

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 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.

Standard PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs
Effective Date: April 1, 2005

A. Introduction

1. **Title: Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program**
2. **Number:** PRC-008-0
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 have a UFLS program
   - **4.2.** Distribution Provider required by its Regional Reliability Organization to have 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 have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).

C. Measures

M1. Each Transmission Owner's and Distribution Provider's UFLS equipment maintenance and testing program contains the elements specified in Reliability Standard PRC-008-0_R1.

M2. Each Transmission Owner and Distribution Provider shall have evidence that it provided the results of its UFLS equipment maintenance and testing program's implementation to its Regional Reliability Organization and NERC on request (within 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: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.2. Level 2: Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation was not provided.

E. Regional Differences

1. None identified.

Standard PRC-009-0 — UFLS Performance Following an Underfrequency Event

Effective Date: April 1, 2005

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.

8 Appendix B – SPP UFLS Standards

The following has been extracted from Section 7 of the October 2004 revision of the Southwest Power Pool Criteria document [2].

7.3 UNDER-FREQUENCY LOAD SHEDDING AND RESTORATION

7.3.1 Automatic Load Shedding

A major disturbance among the interconnected bulk electric system may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. The areas of separation are unpredictable. To provide load relief and minimize the probability of network collapse the following practices are established.

7.3.1.1 Operating Reserve

All SPP operating reserve shall be utilized before resorting to shedding firm load. During a period of declining frequency, there may be violent swings of both real and reactive power. For this reason, all generator governors and voltage regulators shall be kept in automatic service as much as practical.

7.3.1.2 Operating Principles

a. To realize the maximum benefit from a load shedding program the points at which the load is shed in a company area shall be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

b. The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining frequency. The only practical way to remove load from a member in an attempt to stabilize the frequency is to do so automatically by the use of under-frequency relays. Since a geographical area or the timing of a period of low frequency cannot be predicted, all of the designated under-frequency relays on a member system shall be in service at all times. Underfrequency relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

c. The accepted practice of the electric industry is to shed load in a minimum of three steps. Should the frequency continue to decline after these three steps of load shedding, additional action may be required to protect generating machinery from mechanical damage. The actions may include opening of tie-lines, removal of generating units from the bus, additional steps of load shedding, or "island" operation may be utilized automatically with enough load left on a machine or plant to keep it in operation. A member can elect to use any one or a combination of these actions. It is recommended that this operation be performed at 58.5 Hz. Whatever is done by any one member shall be coordinated with neighboring members. A map or chart which shows additional actions that will be taken below a frequency of 58.7Hz shall be furnished to SPP.

7.3.1.3 Implementation

a. Should the utilization of spinning reserve fail to stop a frequency decline, load shedding shall be initiated in steps as indicated below. The goal of the program is to prevent a cascading outage due to a frequency excursion and restore the system to a stable condition. Members must be ready to shed, in three steps, thirty (30) percent of a member's current load regardless of the starting load point (i.e. peak-load, shoulder-load, low-load). This requirement shall be achieved as follows: 1) A member may dynamically arm and disarm UFLS relays to achieve the required load shedding totals, indicated in the chart below, by utilizing a load following program. For the purposes of this section, the term 'dynamically' means that no operator intervention is required to arm or disarm a UFLS relay, or 2) A member that does not dynamically arm and disarm UFLS relays shall install, or have installed on its behalf, UFLS relays with a total capability of shedding a minimum of thirty (30) percent of the member's current load. The relays shall be set to shed the thirty (30) percent total in increments of current load per step, as indicated in the chart below. Once installed, these UFLS relays shall remain in service to trip loads except for periods of testing and maintenance.

Regardless of the technique utilized only the non-intentional delays including operating times of relays and breakers, plus any intentional delay as allowed in Criteria 7.3, shall delay the interruption of pre-event load for all events at the time of each event.

Step	Frequency (hz)	Minimum Load Relief (%)
1	59.3	10
2	59.0	10
3	58.7	10

b. The relays used to accomplish load shedding shall be high speed with no external intentional time delay devices employed. An exception to this policy would be on circuits serving considerable motor load (such as oil field or irrigation pumping load) which would cause the under-frequency relays to incorrectly operate when the source voltage is removed momentarily due to a transmission line fault.

c. Some members may elect to shed more than 10% of the system load on any step, particularly, if they have an adverse ratio of load responsibility to generating capability. This situation is not general and shall be considered on the merits of specific cases.

d. The tripping of any generating unit by under-frequency relays or any other protective device during low frequency conditions shall be so coordinated that these units will not be tripped before the three steps of load shedding have been utilized. Should this not be practical due to the operating characteristics of certain units, then, these members shall protect the interconnected systems by shedding a block of load equal to the capability of the generating unit that will be tripped and at the frequency which will remove the unit from service. If the unit is jointly owned, each of the joint owners shall shed a block of load equal to their share of the unit.

e. The coordination among members becomes critical when actions beyond Step 3 are utilized; particularly, on those members which have established extra high voltage (EHV) terminals as part of their transmission system and/or with generators connected directly to the EHV system. Careful consideration shall be given when opening only one end of an EHV line section which is energized; the open-ended voltage could rise to damaging levels and reactive flow towards the closed-end could have intolerable effects. Further, if generation is connected to the affected portion of the EHV network, that generating capability would be removed from an area where it is sorely needed. Consideration shall be given to the coordination of under frequency relaying of the EHV transmission to maintain generating units on line and if necessary, carry portions of a neighboring system load to do so. System operators shall be alert to the effects of unloading the EHV network and be prepared to remove portions of the network should the voltage rise to intolerable levels.

7.3.1.4 Required Location And Model Data Reporting For Under-frequency Load Shedding Equipment

The number, type and location of Under-frequency Load Shedding (UFLS) equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in databases by the SPP staff for a period of at least three (3) years. These modeling databases shall be monitored as necessary by the SPP System Protection and Control Working Group (SPCWG). The Model Development Working Group, Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities is installed at critical locations throughout the system as determined in power flow and dynamic stability studies. The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, location, breaker, trip frequencies, amount of load shed by trip frequency, relay and breaker operating times, and any intentional delay of breaker clearing. Also required will be any related generation protection, tie tripping schemes, islanding schemes, or any other schemes that are part of or impact the UFLS programs.

7.3.1.5 Requirements for Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means (i.e. self-testing microprocessor relays) to periodically check the functionality and

availability of the UFLS equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility
owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.3.1.6 Periodic Review of Under-frequency Load Shedding Equipment

SPP members shall maintain a list of substations where UFLS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the UFLS equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.3.1.4. The SPCWG will update, if necessary, this UFLS Criteria every three (3) years.

7.3.1.7 Requests for Under-frequency Load Shedding Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners should provide the requested data within five (5) business days with a copy of the requested information forwarded to the SPP. However, it is recognized that significant disturbances may result in a large amount of equipment operations at multiple locations and that some equipment operations must be manually retrieved from the UFLS equipment's locations. These factors may make it impractical to retrieve and properly prepare the records and documentation within five (5) business days. In these cases, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.3.1.8 Restoration

After the frequency has stabilized the following procedure shall be followed.

a. In the event the frequency stabilized below 60 Hz, system operators shall coordinate operations to utilize all available generating capacity to the maximum extent possible in order to restore the frequency to 60 Hz. Deficient systems shall continue to shed load until the frequency can be restored to normal.

b. At 60 Hz the isolated areas shall be synchronized with the remainder of the interconnected systems. Synchronization between individual members shall be performed only upon direct orders of the system operators of both companies involved.

c. System operators shall coordinate load restoration as generating capability, voltage levels and tie-line loadings allow.

d. Any shed load shall be restored only upon direct orders of the system operator. Extreme care shall be exercised as to the rate at which load is restored to the system in order that limits of generation and transmission line loading are not exceeded. Insofar as possible, supervisory control shall be used to restore load; otherwise, manual restoration is preferable to insure positive control by the system operators.

e. It is recommended that a restoration plan be furnished by each company for use by its system operators for implementation of a coordinated and successful recovery.

7.3.2 Requirements of a Regional Under-frequency Load Shedding Program

The SPP shall develop, coordinate, and document a Regional UFLS program.

7.3.2.1 SPP's Coordination of Under-frequency Load Shedding Program

This program shall coordinate UFLS programs within the sub-regions, Region, and where appropriate, among Regions. It shall also coordinate the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration. For an effective plan, SPP shall coordinate programs including generation protection and control, under-voltage load shedding, Regional load restoration, and transmission protection and control. Details to be included shall include those specified in 7.3.1.4. SPP shall periodically conduct and document a technical assessment of the effectiveness of the design and implementation of its UFLS program. The first technical assessment of the program shall be completed by SPP no later than June 1, 2001. These assessments shall be completed at least every five years thereafter or as required by significant changes in system conditions. The documented results of such assessments shall be provided to NERC on request.

7.3.2.2 Coordination of Under-frequency Load Shedding Programs And Analyses With SPP

The facility owners and operators of an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements including automatically shedding load in the amounts and at the locations, frequencies, rates and times consistent with those Regional requirements. When an under-frequency event occurs which is below the initializing set points of their UFLS programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.3.1.7.

7.3.3 Manual Load Shedding

A situation can arise when a control area must reduce load even though the frequency is normal. Since an automatic load shedding program will be of no avail in this case, manual load shedding procedures shall be utilized. One of the basic principles of interconnected operation is that a control area will match the area generation to area load at 60 Hz at all times. Should a generation deficiency develop for any reason, arrangements shall be made with adjacent control areas to cover the deficiency; but failing this, the affected control area shall reduce the area load until the available generation is sufficient to match it. In some cases a generation deficiency can be foreseen and will develop gradually; whereas, in other cases the deficiency will develop immediately with no forewarning. A gradually developing deficiency can probably be offset by using conservation procedures; whereas, an immediate deficiency will probably require customer service interruption. The importance of a load reduction plan cannot be overemphasized. A plan is offered here which can be modified to fit individual cases.

7.3.3.1 Conservation

a. Interruption of service to interruptible customers. Utilize to the extent that the situation requires.

b. Reduction of load in company facilities.

c. Reduction of distribution voltage level. Utilize to the extent possible and as the situation requires.

d. Load reduction by request to company employees and general public. The company employees and the general public shall be notified through news media to curtail the use of electricity.

e. Load reduction by request to bulk power users. Concurrent with voltage reduction and asking employees and the general public to reduce load, bulk power users (municipals and cooperatives) will be asked to reduce load in their areas using the same methods.

f. Load reduction by large use customers. Large use commercial and industrial customers will be requested to curtail electric power usage where such curtailment will not seriously disrupt customers' operations.

7.3.3.2 Service Interruption

Manual load interruption shall be implemented by a pre-determined plan, an example of which follows.

a. Each company operating subdivision shall select distribution circuits in approximately 5% increments in the order of their priority that will be taken out of service. The 5% increments will be labeled "A", "B", "C", "D", "E", and "F". The interruption and the restoration of these circuits will be under the control of the system operator. When the system operator determines that load must be reduced, he shall direct the subdivision operators to open all "A" circuits. This will reduce the system load 5%. If further load reduction is necessary, the system operator shall direct all "B" circuits to be opened which will result in an additional 5% reduction. This shall continue through "C", "D", "E", and "F" until the generation deficiency is eliminated.

b. The objective of this plan is to have no circuits open more than two hours. If the duration of the system emergency exists in excess of two hours and only the "A" circuits have been opened, then at the end of two hours the "B" circuits shall be opened and the "A" circuits reclosed. If a 10% reduction is necessary, "C" and "D" circuits shall be opened and "A" and "B" reclosed, after "A" and "B" have been open for two hours. Obviously, no circuits shall be open longer than is absolutely necessary. The "E" and "F" circuits shall be opened to avoid opening "A" and "B" circuits twice in one day.

c. When a generation deficiency develops, or begins to develop, the system operator shall alert all involved operating personnel to the effect that certain circuits may have to be interrupted. This action will reduce the time required to execute circuit interruption orders of the system operator. Some control areas in SPP have extensive supervisory control systems while others have little, if any, supervisory control. Obviously, any implementation plan shall make best use of available equipment.

Southwest Power Pool

SPP Regional UFLS Standard (PRC-006-SPP-01)
VRF and VSL Justification

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.

VRF and VSL Justifications – R1		
R1	Proposed VRF	High
	NERC VRF Discussion	*Violation of this requirement 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.* *This requirement specifies the tolerances for implementation of the UFLS scheme by UFLS entities that have a total load of 100 MW or greater in the SPP RE Region.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *This requirement is consistent with R9 of PRC-006-1 which addresses a similar reliability goal and has a VRF of "High."*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability*

		objective and a lesser risk reliability objective.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	UFLS entity developed a program, but failed to meet any one (1) of the following five requirements: Part 1.1 (Steps 1-3), Part 1.2, Part 1.3
	Proposed High VSL	UFLS entity developed a program, but failed to meet any two (2) of the following five requirements: Part 1.1 (Steps 1-3), Part 1.2, Part 1.3
	Proposed Severe VSL	UFLS entity developed a program, but failed to meet three (3) or more of the following five requirements: Part 1.1 (Steps 1-3), Part 1.2, Part 1.3 **OR** UFLS entity failed to develop a UFLS program.
	VSL Discussion	*This requirement has multiple parts. Parts 1.1 (Steps 1-3) and Parts 1.2 and 1.3 contribute relatively equally to meeting the requirement. Therefore, the VSLs are based on the number of parts missing. Missing one of Parts 1.1 through 1.3 is Moderate. Missing two of Parts 1.1 through 1.3 is High. Missing three of Parts 1.1 through 1.3 is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignment complies with Guideline 1 because it does 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with Guideline 2B.*
	FERC VSL G3 Violation Severity	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance*

	Level Assignment Should Be Consistent with the Corresponding Requirement	*with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R2		
R2	Proposed VRF	Medium
	NERC VRF Discussion	*Violation of this requirement 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 this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead directly to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.* *This requirement specifies the tolerances for implementation of the UFLS scheme by UFLS entities that have a total load of less than 100 MW in the SPP Region.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *This requirement is consistent with R9 of PRC-006-1 which addresses a similar reliability goal and has a VRF of "High."*
	FERC VRF G4	Guideline 4- Consistency with NERC Definitions of VRFs

	Discussion	*The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	UFLS entity developed a program, but failed to meet one (1) of the requirements in Parts 2.1 through 2.4.
	Proposed Moderate VSL	UFLS entity developed a program, but failed to meet two (2) of the requirements in Parts 2.1 through 2.4.
	Proposed High VSL	UFLS entity developed a program, but failed to meet three (3) of the requirements in Parts 2.1 through 2.4
	Proposed Severe VSL	UFLS entity developed a program, but failed to meet all four (4) of the requirements in Parts 2.1 through 2.4 **OR** UFLS entity failed to develop a UFLS program.
	VSL Discussion	*This requirement has multiple parts. Parts 2.1 – 2.4 contribute relatively equally to meeting the requirement. Therefore, the VSLs are based on the number of parts missing. Missing one of Parts 2.1 through 2.4 is Lower. Missing two of Parts 2.1 through 2.4 is Moderate. Missing three of Parts 2.1 through 2.4 is High. Missing all four of Parts 2.1 through 2.4 is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with Guideline 2B.*

	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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R3		
R3	Proposed VRF	Lower
	NERC VRF Discussion	*Violation of this requirement 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.* *This requirement specifies the characteristics of the underfrequency islanding schemes that each UFLS entity may elect to use.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirements.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address specific characteristics of islanding schemes.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *This requirement has a Lower VRF because it 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe	UFLS entity failed to develop an islanding scheme per the

	VSL	requirement.
	VSL Discussion	*This is a binary requirement. Therefore, the VSL is Severe for failure to perform.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is a binary requirement. The VSL for failure to perform is Severe in compliance with Guideline 2A. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R4		
R4	Proposed VRF	Medium
	NERC VRF Discussion	*Violation of this requirement 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 this 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.* *This requirement specifies the occurrence and timing of UFLS technical assessments performed by the Planning Coordinator.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *This requirement is consistent with R4 of PRC-006-1 which addresses a similar reliability goal and has a VRF of "High." Since this requirement only lists additional reasons why the PC shall conduct a technical study on top of the reasons listed in PRC-006-1, it is therefore assigned a "Medium" VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower	The Planning Coordinator performed a technical assessment

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	VSL	within five years and three months or within one year and three months after one of the situations listed in R4.
	Proposed Moderate VSL	The Planning Coordinator performed a technical assessment within five years and six months or within one year and six months after one of the situations listed in R4.
	Proposed High VSL	The Planning Coordinator performed a technical assessment within five years and nine months or within one year and nine months after one of the situations listed in R4.
	Proposed Severe VSL	The Planning Coordinator performed a technical assessment within six years or within two years after one of the situations listed in R4. **OR** The Planning Coordinator failed to perform a technical assessment.
	VSL Discussion	*This requirement is based on meeting a schedule. Therefore, the VSLs are based on number of months late. Missing the schedule by 3 months is Lower. Missing the schedule by 6 months is Moderate. Missing the schedule by 9 months is High. Missing the schedule by more than 12 months or failed to perform a technical study is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with Guideline 2B.*
	FERC VSL G3 Violation Severity	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or*

	Level Assignment Should Be Consistent with the Corresponding Requirement	*undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R5		
R5	Proposed VRF	Lower
	NERC VRF Discussion	*Violation of this requirement 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. This is a planning requirement that is administrative in nature.* *This requirement specifies the data that must be submitted by each UFLS entity to the Planning Coordinator.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The VRF assigned to this requirement is consistent with the VRF assignment to R6, R7, and R8 of PRC-006-1 which addresses a similar reliability goal.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *This requirement has a Lower VRF because it 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	UFLS entity provided required data more than 30 calendar days and up to and including 45 calendar days following the request.
	Proposed Moderate VSL	UFLS entity provided required data more than 45 calendar days and up to and including 60 calendar days following the request.

		OR UFLS entity did not provide one piece of information listed in R5 (e.g., 5.1.)
	Proposed High VSL	UFLS entity provided required data more than 60 calendar days and up to and including 75 calendar days following the request. **OR** UFLS entity did not provide two pieces of information listed in R5 (e.g., 5.1. and 5.2.)
	Proposed Severe VSL	UFLS entity provided required data more than 75 calendar days following the request. **OR** UFLS entity did not provide required data after the request was made. **OR** UFLS entity did not provide three or more pieces of information listed in R5 (e.g., 5.1. and 5.2. and 5.3.)
	VSL Discussion	*This requirement has timing elements associated with meeting it and has multiple parts that contribute relatively equally to meeting it. Therefore, the VSLs have one component based on number of days late and it has another component based on the number of parts missing. The SDT thought that missing one part was more significant than being more than 30 calendar days and up to and including 45 calendar days late. Therefore, missing the schedule by more than 30 calendar days and up to and including 45 calendar days is Lower. Missing one part or missing the schedule by 46 - 60 days is Moderate. Missing two parts or missing the schedule by 61 - 75 days is High. Missing three or more parts or missing the schedule by more than 75 days is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignment complies with Guideline 1 because it does 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with Guideline 2B.*

	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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*
VRF and VSL Justifications – R6		
R6	Proposed VRF	Lower
	NERC VRF Discussion	*Violation of this requirement 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. This is a planning requirement that is administrative in nature.* *This requirement specifies the data that must be submitted by each Generator Owner to the Planning Coordinator.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3	Guideline 3- Consistency among Reliability Standards

	Discussion	*The VRF assigned to this requirement is consistent with the VRF assignment to R6, R7, and R8 of PRC-006-1 which addresses a similar reliability goal.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *This requirement has a Lower VRF because it 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	Generator Owner provided required data more than 30 calendar days and up to and including 45 calendar days following the request.
	Proposed Moderate VSL	Generator Owner provided required data more than 45 calendar days and up to and including 60 calendar days following the request. **OR** Generator Owner did not provide one piece of information listed in R6 (e.g., 6.1.)
	Proposed High VSL	Generator Owner provided required data more than 60 calendar days and up to and including 75 calendar days following the request. **OR** Generator Owner did not provide two pieces of information listed in R6 (e.g., 6.1. and 6.2.)
	Proposed Severe VSL	Generator Owner provided required data more than 75 calendar days following the request. **OR** Generator Owner did not provide required data after the request was made. **OR** Generator Owner did not provide three or more pieces of information listed in R6 (e.g., 6.1. and 6.2. and 6.3.)
	VSL Discussion	*This requirement has timing elements associated with meeting it and has multiple parts that contribute relatively equally to meeting it. Therefore, the VSLs have one component based on number of days late and it has another component based on the number of parts missing. The SDT thought that missing one part was more significant than being more than 30 calendar days and up to and including 45 calendar days late. Therefore, missing the schedule by more than 30 calendar days and up to and including 45 calendar days is Lower. Missing one part or missing the schedule by 46 - 60 days is Moderate. Missing two parts or missing the schedule by 61 - 75*

		days is High. Missing three or more parts or missing the schedule by more than 75 days is Severe.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R7		
R7	Proposed VRF	Medium
	NERC VRF Discussion	*Violation of this requirement 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 this 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.* *This requirement specifies the minimum characteristics of each generator's protective relay settings to not trip off before the three UFLS steps have occurred.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address generator characteristics.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A

	Proposed Moderate VSL	N/A
	Proposed High VSL	The Generator Owner did not provide technical evidence to the Planning Coordinator demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings for their generating units with operating characteristics that limit the unit's ability to perform in accordance with R7.
	Proposed Severe VSL	The Generator Owner did not verify that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2 due to the generator unit frequency protective relay settings.
	VSL Discussion	*This requirement has two parts. The first part requires the GO to verify that their units will not trip outside the curves in Attachments 1 & 2. Failure to do this results in Severe. If units are found to trip outside the curve, technical data about the unit must be provided to the PC. Failure to do this results in High.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with Guideline 2B.*
	FERC VSL G3 Violation Severity Level Assignment	*The VSL aligns with the language of the requirement, and does not add to nor take away from it. The VSL does not redefine or undermine the requirement's reliability goal. In accordance*

	Should Be Consistent with the Corresponding Requirement	*with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R8		
R8	Proposed VRF	Medium
	NERC VRF Discussion	*Violation of this requirement 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 this 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.* *This requirement specifies the actions of the Planning Coordinator if they receive technical justification that a generator cannot meet the requirements in R7.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address the Planning Coordinator's need to mitigate any generator that trips off during a UFLS event.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower	N/A

VSL	
Proposed Moderate VSL	N/A
Proposed High VSL	The Planning Coordinator determined that the UFLS program was degraded in accordance with R8.1, but did not notify the Generator Owner or the UFLS entity of the Load that they were required to shed.
Proposed Severe VSL	The Planning Coordinator did not determine if the UFLS program performance was degraded due to the removal of any generation identified in accordance with R7.1 and verified in accordance with R8.
VSL Discussion	*This requirement has two parts. The first part requires the PC to determine if the UFLS program performance was degraded due to the removal of the generation. Failure to do this results in Severe. If the PC determines that the system was degraded, but did not notify anyone to shed extra load, then this results in High.*
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined*

	Corresponding Requirement	*objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R9		
R9	Proposed VRF	Medium
	NERC VRF Discussion	*Violation of this requirement 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 this 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.* *This requirement specifies the Generator Owner or other UFLS entity to implement supplementary shedding of Load required by the Planning Coordinator.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirements.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address supplementary load shedding.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A

	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Generator Owner or other UFLS entity did not implement supplementary shedding of Load required by the Planning Coordinator in accordance with R.8.1.1.
	VSL Discussion	*This is a binary requirement. Therefore, the VSL is Severe for failure to perform.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is a binary requirement. The VSL for failure to perform is Severe in compliance with Guideline 2A. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

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.)

Southwest Power Pool

SPP Regional UFLS Standard (PRC-006-SPP-01)
VRF and VSL Justification

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.

VRF and VSL Justifications – R1		
R1	Proposed VRF	High
	VRF Discussion	*This requirement specifies the tolerances for implementation of the UFLS scheme by UFLS entities that have a total load of 100 MW or greater in the SPP RE Region. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *This requirement is consistent with R9 of PRC-006-1 which addresses a similar reliability goal and has a VRF of "High."*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A
	Proposed Moderate	UFLS entity developed a program, but failed to meet any one

	VSL	(1) of the following five requirements: Part 1.1 (Steps 1-3), Part 1.2, Part 1.3
	Proposed High VSL	UFLS entity developed a program, but failed to meet any two (2) of the following five requirements: Part 1.1 (Steps 1-3), Part 1.2, Part 1.3
	Proposed Severe VSL	UFLS entity developed a program, but failed to meet three (3) or more of the following five requirements: Part 1.1 (Steps 1-3), Part 1.2, Part 1.3 **OR** UFLS entity failed to develop a UFLS program.
	VSL Discussion	*This requirement has multiple parts. Parts 1.1 (Steps 1-3) and Parts 1.2 and 1.3 contribute relatively equally to meeting the requirement. Therefore, the VSLs are based on the number of parts missing. Missing one of Parts 1.1 through 1.3 is Moderate. Missing two of Parts 1.1 through 1.3 is High. Missing three of Parts 1.1 through 1.3 is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignment complies with Guideline 1 because it does 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*

	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R2		
R2	Proposed VRF	Medium
	VRF Discussion	*This requirement specifies the tolerances for implementation of the UFLS scheme by UFLS entities that have a total load of less than 100 MW in the SPP Region. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *This requirement is consistent with R9 of PRC-006-1 which addresses a similar reliability goal and has a VRF of "High."*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	UFLS entity developed a program, but failed to meet one (1) of the requirements in Parts 2.1 through 2.4.

	Proposed Moderate VSL	UFLS entity developed a program, but failed to meet two (2) of the requirements in Parts 2.1 through 2.4.
	Proposed High VSL	UFLS entity developed a program, but failed to meet three (3) of the requirements in Parts 2.1 through 2.4
	Proposed Severe VSL	UFLS entity developed a program, but failed to meet all four (4) of the requirements in Parts 2.1 through 2.4 **OR** UFLS entity failed to develop a UFLS program.
	VSL Discussion	*This requirement has multiple parts. Parts 2.1 – 2.4 contribute relatively equally to meeting the requirement. Therefore, the VSLs are based on the number of parts missing. Missing one of Parts 2.1 through 2.4 is Lower. Missing two of Parts 2.1 through 2.4 is Moderate. Missing three of Parts 2.1 through 2.4 is High. Missing all four of Parts 2.1 through 2.4 is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*

	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R3		
R3	Proposed VRF	Lower
	VRF Discussion	*This requirement specifies the characteristics of the underfrequency islanding schemes that each UFLS entity may elect to use. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirements.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address specific characteristics of islanding schemes.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *This requirement has a Lower VRF because it 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	UFLS entity failed to develop an islanding scheme per the requirement.
	VSL Discussion	*This is a binary requirement. Therefore, the VSL is Severe for failure to perform.*
	FERC VSL G1	*The VSL assignments comply with Guideline 1 because they do not have the unintended consequence of lowering the*

	Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*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	*This is a binary requirement. The VSL for failure to perform is Severe in compliance with Guideline 2A. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R4		
R4	Proposed VRF	Medium
	VRF Discussion	*This requirement specifies the occurrence and timing of UFLS technical assessments performed by the Planning Coordinator. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *This requirement is consistent with R4 of PRC-006-1 which addresses a similar reliability goal and has a VRF of "High." Since this requirement only lists additional reasons why the PC shall conduct a technical study on top of the reasons listed in PRC-006-1, it is therefore assigned a "Medium" VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	The Planning Coordinator performed a technical assessment within five years and three months or within one year and three months after one of the situations listed in R4.
	Proposed Moderate VSL	The Planning Coordinator performed a technical assessment within five years and six months or within one year and six months after one of the situations listed in R4.
	Proposed High VSL	The Planning Coordinator performed a technical assessment within five years and nine months or within one year and nine months after one of the situations listed in R4.

	Proposed Severe VSL	The Planning Coordinator performed a technical assessment within six years or within two years after one of the situations listed in R4. **OR** The Planning Coordinator failed to perform a technical assessment.
	VSL Discussion	*This requirement is based on meeting a schedule. Therefore, the VSLs are based on number of months late. Missing the schedule by 3 months is Lower. Missing the schedule by 6 months is Moderate. Missing the schedule by 9 months is High. Missing the schedule by more than 12 months or failed to perform a technical study is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same*

	Single Violation, Not on A Cumulative Number of Violations	*requirement over a period of time.*

VRF and VSL Justifications – R5		
R5	Proposed VRF	Lower
	VRF Discussion	*This requirement specifies the data that must be submitted by each UFLS entity to the Planning Coordinator. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The VRF assigned to this requirement is consistent with the VRF assignment to R6, R7, and R8 of PRC-006-1 which addresses a similar reliability goal.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *This requirement has a Lower VRF because it 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	UFLS entity provided required data more than 30 calendar days and up to and including 45 calendar days following the request.
	Proposed Moderate VSL	UFLS entity provided required data more than 45 calendar days and up to and including 60 calendar days following the request. **OR** UFLS entity did not provide one piece of information listed in R5 (e.g., 5.1.)
	Proposed High VSL	UFLS entity provided required data more than 60 calendar days and up to and including 75 calendar days following the

		request. **OR** UFLS entity did not provide two pieces of information listed in R5 (e.g., 5.1. and 5.2.)
	Proposed Severe VSL	UFLS entity provided required data more than 75 calendar days following the request. **OR** UFLS entity did not provide required data after the request was made. **OR** UFLS entity did not provide three or more pieces of information listed in R5 (e.g., 5.1. and 5.2. and 5.3.)
	VSL Discussion	*This requirement has timing elements associated with meeting it and has multiple parts that contribute relatively equally to meeting it. Therefore, the VSLs have one component based on number of days late and it has another component based on the number of parts missing. The SDT thought that missing one part was more significant than being more than 30 calendar days and up to and including 45 calendar days late. Therefore, missing the schedule by more than 30 calendar days and up to and including 45 calendar days is Lower. Missing one part or missing the schedule by 46 - 60 days is Moderate. Missing two parts or missing the schedule by 61 - 75 days is High. Missing three or more parts or missing the schedule by more than 75 days is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignment complies with Guideline 1 because it does 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with Guideline 2B.*

	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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*
VRF and VSL Justifications – R6		
R6	Proposed VRF	Lower
	VRF Discussion	*This requirement specifies the data that must be submitted by each Generator Owner to the Planning Coordinator. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The VRF assigned to this requirement is consistent with the VRF assignment to R6, R7, and R8 of PRC-006-1 which addresses a similar reliability goal.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *This requirement has a Lower VRF because it 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.*

	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	Generator Owner provided required data more than 30 calendar days and up to and including 45 calendar days following the request.
	Proposed Moderate VSL	Generator Owner provided required data more than 45 calendar days and up to and including 60 calendar days following the request. **OR** Generator Owner did not provide one piece of information listed in R6 (e.g., 6.1.)
	Proposed High VSL	Generator Owner provided required data more than 60 calendar days and up to and including 75 calendar days following the request. **OR** Generator Owner did not provide two pieces of information listed in R6 (e.g., 6.1. and 6.2.)
	Proposed Severe VSL	Generator Owner provided required data more than 75 calendar days following the request. **OR** Generator Owner did not provide required data after the request was made. **OR** Generator Owner did not provide three or more pieces of information listed in R6 (e.g., 6.1. and 6.2. and 6.3.)
	VSL Discussion	*This requirement has timing elements associated with meeting it and has multiple parts that contribute relatively equally to meeting it. Therefore, the VSLs have one component based on number of days late and it has another component based on the number of parts missing. The SDT thought that missing one part was more significant than being more than 30 calendar days and up to and including 45 calendar days late. Therefore, missing the schedule by more than 30 calendar days and up to and including 45 calendar days is Lower. Missing one part or missing the schedule by 46 - 60 days is Moderate. Missing two parts or missing the schedule by 61 - 75 days is High. Missing three or more parts or missing the schedule by more than 75 days is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R7		
R7	Proposed VRF	Medium
	VRF Discussion	*This requirement specifies the minimum characteristics of each generator's protective relay settings to not trip off before the three UFLS steps have occurred. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address generator characteristics.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Generator Owner did not provide technical evidence to the Planning Coordinator demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings for their generating units with operating characteristics that limit the unit's ability to perform in

		accordance with R7.
	Proposed Severe VSL	The Generator Owner did not verify that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2 due to the generator unit frequency protective relay settings.
	VSL Discussion	*This requirement has two parts. The first part requires the GO to verify that their units will not trip outside the curves in Attachments 1 & 2. Failure to do this results in Severe. If units are found to trip outside the curve, technical data about the unit must be provided to the PC. Failure to do this results in High.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

	Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – R8		
R8	Proposed VRF	Medium
	VRF Discussion	*This requirement specifies the actions of the Planning Coordinator if they receive technical justification that a generator cannot meet the requirements in R7. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address the Planning Coordinator's need to mitigate any generator that trips off during a UFLS event.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Planning Coordinator determined that the UFLS program was degraded in accordance with R8.1, but did not notify the Generator Owner or the UFLS entity of the Load that they were required to shed.
	Proposed Severe	The Planning Coordinator did not determine if the UFLS

	VSL	program performance was degraded due to the removal of any generation identified in accordance with R7.1 and verified in accordance with R8.
	VSL Discussion	*This requirement has two parts. The first part requires the PC to determine if the UFLS program performance was degraded due to the removal of the generation. Failure to do this results in Severe. If the PC determines that the system was degraded, but did not notify anyone to shed extra load, then this results in High.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

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VRF and VSL Justifications – R9		
R9	Proposed VRF	Medium
	VRF Discussion	*This requirement specifies the Generator Owner or other UFLS entity to implement supplementary shedding of Load required by the Planning Coordinator. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirements.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address supplementary load shedding.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Generator Owner or other UFLS entity did not implement supplementary shedding of Load required by the Planning Coordinator in accordance with R.8.1.1.
	VSL Discussion	*This is a binary requirement. Therefore, the VSL is Severe for failure to perform.*

	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is a binary requirement. The VSL for failure to perform is Severe in compliance with Guideline 2A. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

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.)

Exhibit G

Violation Severity Level and Violation Risk Factor Analysis

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SPP Regional UFLS Standard (PRC-006-SPP-01)
VRF and VSL Justification

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.

VRF and VSL Justifications – R1		
R1	Proposed VRF	High
	VRF Discussion	*This requirement specifies the tolerances for implementation of the UFLS scheme by UFLS entities that have a total load of 100 MW or greater in the SPP RE Region. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *This requirement is consistent with R9 of PRC-006-1 which addresses a similar reliability goal and has a VRF of "High."*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A
	Proposed Moderate	UFLS entity developed a program, but failed to meet any one

	VSL	(1) of the following five requirements: Part 1.1 (Steps 1-3), Part 1.2, Part 1.3
	Proposed High VSL	UFLS entity developed a program, but failed to meet any two (2) of the following five requirements: Part 1.1 (Steps 1-3), Part 1.2, Part 1.3
	Proposed Severe VSL	UFLS entity developed a program, but failed to meet three (3) or more of the following five requirements: Part 1.1 (Steps 1-3), Part 1.2, Part 1.3 **OR** UFLS entity failed to develop a UFLS program.
	VSL Discussion	*This requirement has multiple parts. Parts 1.1 (Steps 1-3) and Parts 1.2 and 1.3 contribute relatively equally to meeting the requirement. Therefore, the VSLs are based on the number of parts missing. Missing one of Parts 1.1 through 1.3 is Moderate. Missing two of Parts 1.1 through 1.3 is High. Missing three of Parts 1.1 through 1.3 is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignment complies with Guideline 1 because it does 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*

	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R2		
R2	Proposed VRF	Medium
	VRF Discussion	*This requirement specifies the tolerances for implementation of the UFLS scheme by UFLS entities that have a total load of less than 100 MW in the SPP Region. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *This requirement is consistent with R9 of PRC-006-1 which addresses a similar reliability goal and has a VRF of "High."*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	UFLS entity developed a program, but failed to meet one (1) of the requirements in Parts 2.1 through 2.4.

	Proposed Moderate VSL	UFLS entity developed a program, but failed to meet two (2) of the requirements in Parts 2.1 through 2.4.
	Proposed High VSL	UFLS entity developed a program, but failed to meet three (3) of the requirements in Parts 2.1 through 2.4
	Proposed Severe VSL	UFLS entity developed a program, but failed to meet all four (4) of the requirements in Parts 2.1 through 2.4 **OR** UFLS entity failed to develop a UFLS program.
	VSL Discussion	*This requirement has multiple parts. Parts 2.1 – 2.4 contribute relatively equally to meeting the requirement. Therefore, the VSLs are based on the number of parts missing. Missing one of Parts 2.1 through 2.4 is Lower. Missing two of Parts 2.1 through 2.4 is Moderate. Missing three of Parts 2.1 through 2.4 is High. Missing all four of Parts 2.1 through 2.4 is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*

	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R3		
R3	Proposed VRF	Lower
	VRF Discussion	*This requirement specifies the characteristics of the underfrequency islanding schemes that each UFLS entity may elect to use. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirements.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address specific characteristics of islanding schemes.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *This requirement has a Lower VRF because it 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	UFLS entity failed to develop an islanding scheme per the requirement.
	VSL Discussion	*This is a binary requirement. Therefore, the VSL is Severe for failure to perform.*
	FERC VSL G1	*The VSL assignments comply with Guideline 1 because they do not have the unintended consequence of lowering the*

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	Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*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	*This is a binary requirement. The VSL for failure to perform is Severe in compliance with Guideline 2A. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R4		
R4	Proposed VRF	Medium
	VRF Discussion	*This requirement specifies the occurrence and timing of UFLS technical assessments performed by the Planning Coordinator. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *This requirement is consistent with R4 of PRC-006-1 which addresses a similar reliability goal and has a VRF of "High." Since this requirement only lists additional reasons why the PC shall conduct a technical study on top of the reasons listed in PRC-006-1, it is therefore assigned a "Medium" VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	The Planning Coordinator performed a technical assessment within five years and three months or within one year and three months after one of the situations listed in R4.
	Proposed Moderate VSL	The Planning Coordinator performed a technical assessment within five years and six months or within one year and six months after one of the situations listed in R4.
	Proposed High VSL	The Planning Coordinator performed a technical assessment within five years and nine months or within one year and nine months after one of the situations listed in R4.

	Proposed Severe VSL	The Planning Coordinator performed a technical assessment within six years or within two years after one of the situations listed in R4. **OR** The Planning Coordinator failed to perform a technical assessment.
	VSL Discussion	*This requirement is based on meeting a schedule. Therefore, the VSLs are based on number of months late. Missing the schedule by 3 months is Lower. Missing the schedule by 6 months is Moderate. Missing the schedule by 9 months is High. Missing the schedule by more than 12 months or failed to perform a technical study is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same*

	Single Violation, Not on A Cumulative Number of Violations	*requirement over a period of time.*

VRF and VSL Justifications – R5		
R5	Proposed VRF	Lower
	VRF Discussion	*This requirement specifies the data that must be submitted by each UFLS entity to the Planning Coordinator. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The VRF assigned to this requirement is consistent with the VRF assignment to R6, R7, and R8 of PRC-006-1 which addresses a similar reliability goal.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *This requirement has a Lower VRF because it 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	UFLS entity provided required data more than 30 calendar days and up to and including 45 calendar days following the request.
	Proposed Moderate VSL	UFLS entity provided required data more than 45 calendar days and up to and including 60 calendar days following the request. **OR** UFLS entity did not provide one piece of information listed in R5 (e.g., 5.1.)
	Proposed High VSL	UFLS entity provided required data more than 60 calendar days and up to and including 75 calendar days following the

		request. **OR** UFLS entity did not provide two pieces of information listed in R5 (e.g., 5.1. and 5.2.)
	Proposed Severe VSL	UFLS entity provided required data more than 75 calendar days following the request. **OR** UFLS entity did not provide required data after the request was made. **OR** UFLS entity did not provide three or more pieces of information listed in R5 (e.g., 5.1. and 5.2. and 5.3.)
	VSL Discussion	*This requirement has timing elements associated with meeting it and has multiple parts that contribute relatively equally to meeting it. Therefore, the VSLs have one component based on number of days late and it has another component based on the number of parts missing. The SDT thought that missing one part was more significant than being more than 30 calendar days and up to and including 45 calendar days late. Therefore, missing the schedule by more than 30 calendar days and up to and including 45 calendar days is Lower. Missing one part or missing the schedule by 46 - 60 days is Moderate. Missing two parts or missing the schedule by 61 - 75 days is High. Missing three or more parts or missing the schedule by more than 75 days is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignment complies with Guideline 1 because it does 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with Guideline 2B.*

	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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*
VRF and VSL Justifications – R6		
R6	Proposed VRF	Lower
	VRF Discussion	*This requirement specifies the data that must be submitted by each Generator Owner to the Planning Coordinator. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The VRF assigned to this requirement is consistent with the VRF assignment to R6, R7, and R8 of PRC-006-1 which addresses a similar reliability goal.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *This requirement has a Lower VRF because it 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.*

	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	Generator Owner provided required data more than 30 calendar days and up to and including 45 calendar days following the request.
	Proposed Moderate VSL	Generator Owner provided required data more than 45 calendar days and up to and including 60 calendar days following the request. **OR** Generator Owner did not provide one piece of information listed in R6 (e.g., 6.1.)
	Proposed High VSL	Generator Owner provided required data more than 60 calendar days and up to and including 75 calendar days following the request. **OR** Generator Owner did not provide two pieces of information listed in R6 (e.g., 6.1. and 6.2.)
	Proposed Severe VSL	Generator Owner provided required data more than 75 calendar days following the request. **OR** Generator Owner did not provide required data after the request was made. **OR** Generator Owner did not provide three or more pieces of information listed in R6 (e.g., 6.1. and 6.2. and 6.3.)
	VSL Discussion	*This requirement has timing elements associated with meeting it and has multiple parts that contribute relatively equally to meeting it. Therefore, the VSLs have one component based on number of days late and it has another component based on the number of parts missing. The SDT thought that missing one part was more significant than being more than 30 calendar days and up to and including 45 calendar days late. Therefore, missing the schedule by more than 30 calendar days and up to and including 45 calendar days is Lower. Missing one part or missing the schedule by 46 - 60 days is Moderate. Missing two parts or missing the schedule by 61 - 75 days is High. Missing three or more parts or missing the schedule by more than 75 days is Severe.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R7		
R7	Proposed VRF	Medium
	VRF Discussion	*This requirement specifies the minimum characteristics of each generator's protective relay settings to not trip off before the three UFLS steps have occurred. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address generator characteristics.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Generator Owner did not provide technical evidence to the Planning Coordinator demonstrating that the unit cannot operate within the specified frequency range without causing equipment damage or violating manufacturer's published equipment ratings for their generating units with operating characteristics that limit the unit's ability to perform in

		accordance with R7.
	Proposed Severe VSL	The Generator Owner did not verify that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2 due to the generator unit frequency protective relay settings.
	VSL Discussion	*This requirement has two parts. The first part requires the GO to verify that their units will not trip outside the curves in Attachments 1 & 2. Failure to do this results in Severe. If units are found to trip outside the curve, technical data about the unit must be provided to the PC. Failure to do this results in High.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

	Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – R8		
R8	Proposed VRF	Medium
	VRF Discussion	*This requirement specifies the actions of the Planning Coordinator if they receive technical justification that a generator cannot meet the requirements in R7. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirement VRF assignments.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address the Planning Coordinator's need to mitigate any generator that trips off during a UFLS event.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Planning Coordinator determined that the UFLS program was degraded in accordance with R8.1, but did not notify the Generator Owner or the UFLS entity of the Load that they were required to shed.
	Proposed Severe	The Planning Coordinator did not determine if the UFLS

	VSL	program performance was degraded due to the removal of any generation identified in accordance with R7.1 and verified in accordance with R8.
	VSL Discussion	*This requirement has two parts. The first part requires the PC to determine if the UFLS program performance was degraded due to the removal of the generation. Failure to do this results in Severe. If the PC determines that the system was degraded, but did not notify anyone to shed extra load, then this results in High.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is not a binary requirement, therefore Guideline 2A does not apply. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

VRF and VSL Justifications – R9		
R9	Proposed VRF	Medium
	VRF Discussion	*This requirement specifies the Generator Owner or other UFLS entity to implement supplementary shedding of Load required by the Planning Coordinator. The VRF assigned to this requirement meets FERC's Five Guidelines for setting VRFs as noted below:*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *The team did not address Guideline 1 directly because of an apparent 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 SDT believes that Guideline 4 is reflective of the intent of VRFs and therefore concentrated its approach on the reliability impact of the requirements.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *This guideline is not applicable since this requirement does not have sub-requirements.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *The requirements in PRC-006-1 do not address supplementary load shedding.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *The medium VRF assignment is consistent with the NERC definition in that it is 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.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *This requirement does not comingle a higher risk reliability objective and a lesser risk reliability objective.*
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Generator Owner or other UFLS entity did not implement supplementary shedding of Load required by the Planning Coordinator in accordance with R.8.1.1.
	VSL Discussion	*This is a binary requirement. Therefore, the VSL is Severe for failure to perform.*

	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The VSL assignments comply with Guideline 1 because they 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	*This is a binary requirement. The VSL for failure to perform is Severe in compliance with Guideline 2A. The VSL is written in clear and unambiguous language in compliance with 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. The VSL does not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.*
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	*The VSL assignment complies with Guideline 4, because it is based on a single violation of a Reliability Standard and is not based on a cumulative number of violations of the same requirement over a period of time.*

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.)

Exhibit H

Standard Drafting Team Roster

Southwest Power Pool

Regional Standard Drafting Team for PRC-006-SPP-01

Name and Title Affiliation Contact Info	Biography
Heidt Melson, SPCWG Chairman Manager Transmission Engineering Operation Xcel Energy 806-640-6356 heidt.melson@xcelenergy.com 6086 W. 48th Amarillo, TX 79109	Mr. Melson has 32 years of experience in the electric utility industry. Since 2002 he has been the Manager Transmission Engineering Operation for Xcel Energy. He manages a team of engineers and non-engineers and is responsible for commissioning new bulk power system equipment, transmission control room support, and transmission substation communication. Mr. Melson has designed, installed, and commissioned transmission projects from 69 to 345 kV and power plants up to 550 MW. He has experience conducting detailed analysis of system events and disturbances, improving correct protective relay operation, and meeting compliance requirements in three jurisdictions. Mr. Melson received his B.S.E.E. from Texas Tech University. He is a licensed Professional Engineer in Texas, Oklahoma, and New Mexico and a Master Electrician in Texas.
Edwin (Bud) Averill, SPCWG Member Project Engineer Grand River Dam Authority 918-825-0280 ext. 7743 baverill@grda.com PO Box 1128 Pryor, OK 74362	Mr. Averill has served in the electrical utility industry since 1971, when he began his career as an Electrical Engineer with Systems Engineering. He worked for Public Service Company of Oklahoma from 1972-1997 in several roles: Electrical Engineer/Project Manager, Electrical & Instrument-Control Supervisor, and Senior Electrical Engineer. Mr. Averill worked for Central and South West Services from 1997-2000 as a Senior Electrical Engineer for both System Protection and Substation Design. He worked at American Electric Power from 2000-2005 as a Senior Lead Engineer for Station Projects Engineering. Mr. Averill joined Grand River Dam Authority in 2005 and serves as a Project Engineer. Mr. Averill received his B.S.E.E. from Oklahoma State University and is a licensed Professional Engineer in Oklahoma. He belongs to and has served leadership roles with the Institute of Electrical & Electronic Engineers-Tulsa Section, Tulsa Engineering Foundation, and Tulsa Engineering Challenge. He also serves on the Electrical Board of Examinations and Appeals for the City of Tulsa and on the Board of Advisors-Electrical for Tulsa Junior College.
Brent Carr, SPCWG Member Senior Design Engineer-Transmission Design Arkansas Electric Cooperative Co. 501-570-2437 bcarr@aecc.com 1 Cooperative Way Little Rock, AR 72209	Mr. Carr has 11 years of experience with Arkansas Electric Cooperative Corporation and 6 years of previous experience in the manufacturing industry. As a Senior Design Engineer for Transmission Design, his responsibilities include preparing physical and electrical designs for power substations, conducting load and forecasting studies, managing projects, and developing equipment specifications and work contracts. Mr. Carr serves as a Board advisor for the University of Arkansas & University of South Carolina Grid-connected Advanced Power Electronics Systems research center and is Chairman of EPRI's Fault Current and Substation Grounding task force.

	Mr. Carr is a licensed Professional Engineer and Master Electrician in Arkansas. He received his B.S.E.E and M.S.E.E degrees from the University of Arkansas.
Louis Guidry, SPCWG Member Manager, NERC Compliance & Training Cleco Power LLC 318-484-7495 louis.guidry@cleco.com 2030 Donahue Ferry Road Pineville, LA 71360	Louis Guidry has been with Cleco for 26 years. His career at Cleco has included work related to substation design, communication systems, transmission system planning, transmission relaying and controls, system protection planning and design, and system protection apparatus maintenance. In 1998, Mr. Guidry was appointed Lead Engineer in his area, and in 2002 he became Manager of Electric System Maintenance. He held that position until his appointment as Director of Transmission and Distribution Reliability Compliance in 2006. Since 2006, Mr. Guidry has worked exclusively in the area of reliability compliance and recently was promoted to Manager of NERC Compliance and Training. In addition to his work experience at Cleco, Mr. Guidry is a licensed Professional Engineer and has earned the NERC Reliability Operator Certification. He serves on the SPP Members Compliance Group in addition to the SPCWG.
Rick Gurley, SPCWG Member Manager, Protection & Control Engineering American Electric Power 918-599-2263 RLGurley@aep.com 212 East 6th. Street Tulsa, OK 74119	Mr. Gurley has 32 years of experience in the electric utility industry and has served 28 years with AEP and its subsidiaries. He has worked in a number of areas including transmission and substation construction and maintenance, protection and control engineering, transmission planning, distribution operations, and transmission asset management. Mr. Gurley's current duties involve managing an engineering group responsible for the protection and control design of all substation projects in the western four states of AEP's service territory. Mr. Gurley is a licensed Professional Engineer in Texas. He is a member of the Industrial Advisory Board for the Electrical and Computer Engineering Department at Texas Tech University, a member of the NERC Protection System Misoperations Task Force, and a past member of the ERCOT System Protection Working Group.
Tim Hinken, SPCWG Member Supervisor of System Protection Engineering Kansas City Power & Light Company 816-245-3784 Tim.Hinken@kcpl.com 4400 East Front Street Kansas City, MO 64120	Tim Hinken has worked for Kansas City Power & Light for 31 years. He served six years as Supervisor of System Protection Engineering with responsibilities for supervising, designing, and coordinating protection systems. He served one year as Supervisor of Substation Engineering where he was responsible for supervising and designing substation construction projects. As a System Protection Engineer for five years, Mr. Hinken's responsibilities included material specification, design, coordination, and commissioning testing for generation protection systems, T&D substations, and distribution equipment. Mr. Hinken served 10 years as a Substation Engineer, responsible for design, material specification, and commissioning of substation construction projects. During his three years as a District Engineer his responsibilities included providing new or expanded electric service to commercial and industrial customers in the Kansas City area. Mr. Hinken has a B.S.E.E. from the University of Missouri Kansas City and a M.S.E.E. from the University of Missouri Columbia. He is a licensed Professional Engineer in Missouri and Kansas.

Shawn Jacobs, SPCWG Member Lead Engineer Oklahoma Gas & Electric 405-553-5910 jacobssw@oge.com 3220 South High Oklahoma City, OK 73101	Shawn W. Jacobs is a Lead Engineer at Oklahoma Gas and Electric Company in Oklahoma City. He has 10 years of System Protection and Control experience at OG&E and is currently responsible for transmission/substation protective system settings and coordination, disturbance event/misoperation analysis, and NERC CIP and PRC compliance. Mr. Jacobs received his B.S.E.E. from the University of Oklahoma and is a licensed Professional Engineer in Oklahoma.
Ron McIvor, SPCWG Member Principal Protection Engineer Omaha Public Power District 402-552-4925 rmcivor@oppd.com 1101 N. 180th Street Elkhorn, NE 68022	Mr. McIvor has served OPPD for 35 years in the area of protective relaying. During his OPPD career he has served as Engineer, Senior Engineer, Relay Engineer, Lead Relay Engineer, and Lead Protection Engineer. In his present position as Principal Protection Engineer he is responsible for providing technical training to protection engineering staff and compliance with NERC PRC standards. Mr. McIvor is a licensed Professional Engineer in Nebraska, a Senior Member of IEEE, and a member of the Midwest Reliability Organization Protective Relay Subcommittee.
Lynn Schroeder, SPCWG Member Manager of Protection and Control Engineering Westar Energy, Inc. 316-291-8840 lynn.schroeder@westarenergy.com 4400 N. Seneca Wichita, KS 67204	Ms. Schroeder has 24 years of utility experience with Westar Energy. Before serving in her current role as Manager of the Protection and Control Engineering, she spent 16 years as a Protection and Control Engineer, three years as a Construction Supervisor, and two years as a Distribution Engineer. Ms. Schroeder has served 15 years as the Westar representative to the SPP SPCWG; for two of those years she served as chair. She also represents SPP on the NERC System Protection and Control Subcommittee. Ms. Schroeder has served as an Adjunct Professor for Wichita State University and Kansas State University, teaching Power System Analysis and Design and AC Circuits respectively. Ms. Schroeder has a B.S.E.E. and is a licensed Professional Engineer in Kansas.
Mathew Thykkuttathil, SPCWG Member Transmission Engineer-III Sunflower Electric Power Corp. 620-272-5417 mthykku@sunflower.net P.O.Box1649 Garden City, KS 67846	Mr. Thykkuttathil has 29 years of experience in the electric utility industry. He currently serves Sunflower as Transmission Engineer-III. He has responsibilities related to Sunflower's system protection and controls and assists other engineers with questions on system modeling: load flow and short circuit, substation design, ground grid design, capacitor bank design, and distribution feeder protection/coordination. Previously, he served for nine years as an Assistant Engineer for the Kerala State Electricity Board in India. Mr. Thykkuttathil has a degree in Electrical Engineering from the University of Kerala, India.
Stephen Wadas, SPCWG Member Protection Engineering Technical Lead Nebraska Public Power District 402-563-5917 stwadas@nppd.com 1414 15th St. Columbus, NE 68601	Mr. Wadas has 22 years of experience in the electric utility industry. He has served NPPD for 16 years in the Protection, Control, and Automation Department. Before becoming a Protection Engineering Technical Lead he served as a Protection Engineer. He also served six years as an Electrical Engineer in the Fossil Engineering Department. Mr. Wadas has a B.S.E.E. from the University of Nebraska-Lincoln. He is a Past State President of the National Society of Professional Engineers and currently serves in the Society's House of Delegates. He is a past

	member of the Midwest Reliability Organization's Protective Relay Subcommittee and a member of the NERC PRC-006 Committee.
Ken Zellefrow, SPCWG Member Supervisor-Substation Engineering City Utilities of Springfield, MO 417-831-8305 ken.zellefrow@cityutilities.net 740 N. Belcrest Springfield, MO 65802	Mr. Zellefrow has 29 years of utility experience. He has served in his current position as Supervisor of Substation Engineering for eight years. He served City Utilities of Springfield as an Engineer and Senior Engineer for 23 years, and served El Paso Electric Company as a Standards Engineer and Supervisor. Mr. Zellefrow is a member of IEEE Power & Energy Society and served as an alternate SDT member for NERC's PRC-002 Disturbance Monitoring Equipment standard. Mr. Zellefrow received his B.S.E.E. from New Mexico State University and is a licensed Professional Engineer in Missouri.
Jason Speer, SPCWG Staff Secretary Senior Engineer (Interregional Coordination) Southwest Power Pool 501-614-3301 jspeer@spp.org 415 North McKinley Street Little Rock, AR 72205-3020	Mr. Speer has served in the electric utility industry for ten years. He joined SPP in 2005 as an Engineer I and is now a Senior Engineer. In addition to serving as SPCWG staff secretary for five years, he contributes to Eastern Interconnection Planning Collaborative studies and until recently was responsible for preparing SPP's TPL Compliance assessments and reports. Mr. Speer is past member of NERC's Load Forecasting and Data Coordination Working Groups. He received his B.S.E.E. from Arkansas Tech University.

Exhibit I

2010 Evaluation and Assessment of Southwest Power Pool Under-Frequency Load Shedding Scheme

Powertech

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2010 Evaluation and Assessment of Southwest Power Pool (SPP) Under-Frequency Load Shedding Scheme

Powertech Project: 19993-21-00
Report No.: 19993-21-00-A

Prepared by:

Powertech Labs Inc. (PLI)

For:

Southwest Power Pool (SPP)

December 22, 2010

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Executive Summary

Southwest Power Pool (SPP) retained Powertech Labs Inc. (PLI) to assess the performance of SPP's Under Frequency Load Shedding (UFLS) scheme as part of compliance requirements for UFLS programs as defined by NERC/SPP standards for under frequency load shedding. PLI conducted studies to assess the effectiveness of the existing UFLS program in the SPP power system. As part of NERC compliance every five years SPP should conduct a study, similar to the one reported herein, in order to provide evidence that SPP UFLS program is effective to cope with system changes. The last of such studies of the SPP system was conducted in the year 2006.

In this project, the UFLS relay data submitted by SPP members was reviewed and the SPP power system was studied under a number of scenarios with varying degree of mismatches between load and generation to evaluate performance of the UFLS scheme. The main findings of this study are summarized below:

- SPP has maintained and updated its UFLS relay data every five years (the last update was reported in 2006). This data includes sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.

- Review of the SPP members UFLS relay data revealed that relay set-points and amount of load shed in each stage closely follows the provisions of NERC/SPP requirements.

- The results of studies conducted and review of the relay data showed coordination exists between the UFLS program, under-voltage UFLS inhibit setting, generator under-frequency protection, and transmission protection.

- A number of scenarios with varying amount of generation/load mismatches were simulated, and in all of the simulations, the system frequency was adequately controlled and the SPP power system maintained reasonable stability. The result proved the adequacy of the UFLS program under the simulated scenarios.

- Simulation of over-shedding of up to 15%, in the most severe generation loss scenario (30% generation loss), showed the resultant over-frequency to be acceptable and no generator tripping due to over-speed is anticipated.

- The effect of universal UFLS scheme trip time setting was investigated. Scenarios with 30 and 40 cycles were simulated, and their results were reported and compared. The study indicated that with an intentional delay of 40 cycles (0.667 seconds) the UFLS program operates effectively and the SPP system maintains reasonable stability.

Overall, it is concluded that the SPP's UFLS scheme complies with the NERC/SPP requirements.

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1 Introduction

1.1 Application of Under Frequency Load Shedding Scheme

Power system steady-state operation requires a balance between generation and load. A sudden loss of generation due to abnormal conditions, such as loss of generating units due to faults, disturbs this balance and the system frequency begins to deviate from its nominal. System operation at low frequencies impairs the operation of power system components especially turbines and, if not corrected, can lead to tripping of additional generators thereby further aggravating the situation. To arrest frequency decline, the governors of the generators with spinning reserve attempt to make-up for the lost generation. If the frequency decline is too fast (due to severe mismatch between load and generation) and the governors cannot react fast enough or spinning reserve is not adequate, under-frequency relays are used for initiating automatic load shedding as a last resort to maintain system integrity by implementing an Under-Frequency Load Shedding (UFLS) program[1]. The under-frequency load shedding scheme must be properly designed to:

- Prevent excessive load shedding which may result in over-frequency conditions or unnecessary loss of service continuity and revenue,
- Avoid insufficient load shedding which in turn may lead to system blackout, and
- Provide sufficient load shedding to maintain the frequency within acceptable operating range.

Static analysis of power systems is widely used to design UFLS schemes. In such analysis, the equivalent inertia of the power system is obtained, the effect of voltage variation is ignored, and the whole system is assumed to be a single mass with parameters (such as load damping) being approximated by lumped values. Governor response of connected generation is also ignored for the sake of simplicity. The simplicity of static analysis makes it useful for rapid evaluation of numerous UFLS schemes to select a few designs that result in acceptable performance over a wide range of conditions. However, for detailed assessment of UFLS schemes, dynamic simulation is required. The more detailed revelation of system response makes dynamic analysis useful for in depth analysis of a short list of alternative UFLS schemes.

A coordinated automatic under-frequency load shedding program is required to maintain power system security during major system frequency declines. The North American Electric Reliability Council (NERC) has provided Reliability Standards, Requirements, Measures and Levels of Compliance to ensure the proper implementation of UFLS programs. NERC regional members have developed their own standards based on the NERC standards that also address their specific needs. For the sake of completeness, NERC and SPP polices regarding UFLS program are reproduced in Appendix A & B respectively.

[1] Load shedding is an *emergency control action* typically implemented to recover a system from *Emergency* state to *Normal* state.

1.2 Objectives

As part of compliance with the NERC and SPP requirements for UFLS program, Southwest Power Pool (SPP) contracted Powertech Labs Inc. (PLI) to evaluate the performance of their UFLS scheme. The objectives of this study are as follows:

- To review and convert SPP's under frequency relay data into a format suitable for use for time-domain simulations.
- To conduct simulations on the SPP power system to determine if the SPP UFLS scheme is compliant with the NERC/SPP requirements in maintaining system security under severe imbalance between load and generation scenarios.
- To determine if the SPP system remains stable for up to 45% load shedding.
- To determine sensitivity results with respect to a few intentional time delays in UFLS program.
- To recommend modifications to the SPP UFLS scheme if deemed necessary.
- To determine the effect of under-voltage inhibit setting of no greater than 85% nominal voltage on the UFLS program.
- To provide documentation detailing the results of the study.

2 Scope and Study Approach

The scope of this project includes review of the SPP UFLS program to verify its performance against NERC and SPP criteria, and recommend modifications if needed. The evaluation is to be performed with a time-domain simulation program using SPP submitted powerflow, dynamic data and the UFLS relay data. The present study focuses on the SPP region and does not consider UFLS schemes outside of SPP.

The study will examine system performance over the time period needed for the UFLS relays to operate, but will not include AGC action or a full study of system islanding scenarios.

2.1 Modeling Requirements

Accurate UFLS performance evaluation requires simulation of power systems in the time-domain under several severe imbalance conditions between generation and load. It is therefore important to model the dynamics of the power system components in detail. The dynamic representations of the following power system components are most crucial in UFLS evaluation:

- UFLS relays including generator under-frequency protection and under-frequency system islanding schemes,
- Generators including their spinning reserve,
- Governors and turbines,
- Excitation systems,
- Loads with frequency/voltage dependency.

In the UFLS evaluation studies, representation of dynamic action of Under Load Tap Changing transformers (ULTC) is not necessary since their response times are much longer than the time frame of UFLS operations. The dynamic models of over/under excitation limiters are also not required as long as reactive power of generators are monitored and units with reactive power exceeding their reactive power capabilities are identified and disconnected if the under/over excitation condition is sustained.

The dynamic data submitted by SPP was reviewed and found adequate in regard to the dynamic representation of power system components described above. The submitted UFLS relay data was reviewed and all models relevant to the study were generated and incorporated into the system model. A commonly accepted frequency dependent load model was also adopted in this study (3.4).

2.2 Selection of Appropriate Scenarios in the UFLS Assessment

The powerflow basecase, Summer 2011, submitted by SPP is implemented as the loading condition for the system under the study. For this loading condition, three scenarios of generation/load imbalances were developed. These scenarios were designed to fully exercise the UFLS program to assess compliance with NERC and SPP standards. This calls for examination of several levels of imbalance between generation and load to trigger different levels of load shedding stages. Time-domain simulations were conducted for generation loss scenarios. Extensive monitoring and analysis of the simulations were performed to ensure that the frequency declines are properly arrested and system security is maintained.

2.3 Tools Used to Assess the UFLS scheme

In this project, the Transient Security Assessment Tool (TSAT) developed by Powertech Labs Inc. was used to evaluate the effectiveness of the SPP UFLS program. TSAT is a time-domain simulation program with comprehensive modeling capabilities that accepts system data in (Siemens/PTI) PSS/E data format. Powertech's powerflow program, Powerflow & Short circuit Analysis Tool (PSAT), was also used to reduce the NERC powerflow basecase to include only the SPP power system.

3 Model Assembly and Data Sanity Checking

3.1 Powerflow Basecase

SPP provided one powerflow basecase. This powerflow corresponds to the 2011 peak load condition. The powerflow results summary (ordered in terms of SPP areas) for this basecase is provided in Table 3-1.

Table 3-1: Power Flow Summary for Peak Load of Year 2011

Area		Generation		Load		Losses		Export	
Number	**Name**	**MW**	**MVAr**	**MW**	**MVAr**	**MW**	**MVAr**	**MW**	**MVAr**
502	CELE	2894.76	1124.40	2505.28	666.84	66.40	632.99	405.85	375.08
503	LAFA	222.79	40.00	485.47	19.07	7.32	84.98	-270.00	-51.38
504	LEPA	161.06	19.28	225.00	7.87	0.06	0.15	-64.61	11.30
515	SWPA	1993.68	517.67	898.60	243.50	34.17	377.95	1061.19	239.72
520	AEPW	9460.07	1319.17	10339.80	1906.39	271.79	2914.30	-1136.79	249.36
523	GRDA	1121.08	179.37	1029.49	210.69	19.55	330.01	70.71	-68.54
524	OKGE	7320.33	903.75	6324.73	1521.24	150.53	1850.11	836.88	283.87
525	WFEC	1204.02	104.93	1382.50	364.47	50.35	346.92	-229.87	-196.30
526	SWPS	5895.59	814.91	5936.61	1344.16	202.45	1739.59	-245.23	-2.67
527	OMPA	55.72	21.96	666.35	133.28	2.36	15.25	-613.40	-115.28
531	MIDW	124.61	13.66	376.45	79.60	8.50	27.98	-238.47	-29.54
534	SUNC	544.26	1.73	451.60	145.50	17.40	170.84	7.44	4.95
536	WERE	6101.78	999.06	6014.75	1481.11	136.54	1858.83	-176.02	-210.13
539	WEPL	387.51	13.73	678.40	201.80	21.48	139.37	-189.72	83.46
540	MIPU	1156.59	402.71	2101.40	654.12	31.82	375.84	-932.03	-108.01
541	KACP	4327.93	1251.68	3515.62	800.46	69.92	1188.45	726.01	193.81
542	KACY	574.77	65.87	554.03	126.34	3.74	84.95	16.99	-132.51
544	EMDE	1122.64	100.06	1177.49	122.59	38.12	277.80	-92.97	20.09
545	INDN	216.87	10.41	322.44	80.97	2.44	21.85	-108.03	-58.84
546	SPRM	741.80	352.30	784.85	269.78	9.97	166.26	-53.24	19.17
640	NPPD	3118.84	93.69	3659.72	1131.30	127.03	1186.02	-667.92	133.08
645	OPPD	3273.60	1082.58	2972.12	958.73	34.52	681.68	266.94	-40.29
650	LES	262.91	24.00	803.40	159.50	9.51	165.75	-549.98	5.10
	TOTAL:	52,283.21	9,456.92	53,206.10	12,629.32	1,316.00	14,637.87	-2,176.25	605.50

3.2 Model reduction

The powerflow basecase submitted by SPP contain all regions of NERC power system. To be able to assess the adequacy of the UFLS program in the SPP region, it is necessary to create scenarios in which large mismatches between generation and load exist. Modeling the entire NERC network for these types of scenarios presents two practical problems:

(i) The amount of mismatch between generation and load would have to be significantly substantial to observe large frequency excursion (note NERC load is ~670,000 MW) which is considered unrealistic unless islanding scenarios are explicitly considered.
(ii) To judge the performance of UFLS program in SPP, load shedding relays in all of NERC regions would have to be modeled. This is considered impractical for this type of study.

Because of aforementioned limitations, a practical approach is to deal with a reduced system model in which only the SPP network is explicitly represented and SPP network imports or exports to the rest of the NERC system are replaced with equivalent generation or loads ("block loaded").

Therefore, a powerflow based network reduction technique was used in which all tie lines to/from SPP are replaced with equivalent power flow injections at the tie line ends. In this process a few islands with a small number of buses were created. These islands were ignored as a new basecase was created for SPP power system. With this setup, the tie-line flows could be changed to represent disturbances in the NERC system resulting in additional generation/load mismatch seen by the SPP system.

<u>Note regarding reduction process</u>:

The reduction process rendered a system with 19 islands. The largest island, which considered as the main system, contained 6,207 buses. This island was considered as the basecase throughout this report. The additional 18 islands were reasonably small as they mostly contain two or three buses, with a total of 25 buses from SPP areas. These buses were completely located within non-SPP areas with no direct connection to any SPP bus. These islands were not incorporated within this study and not reported in this context.

The following table provides a comparison between the complete and reduced basecase powerflow results for SPP areas generation and load.

Table 3-2: Powerflow summary for the Complete and Reduced basecases

Area		Generation (MW)		Load (MW)	
Number	**Name**	**Orig.**	**Reduced**	**Orig.**	**Reduced**
502	CELE	2,894.76	2,894.76	2,505.28	1,851.98
503	LAFA	222.79	222.79	485.47	485.47
504	LEPA	161.06	47.06	225.00	61.00
515	SWPA	1,993.68	1,941.38	898.60	898.60
520	AEPW	9,460.07	9,460.07	10,339.80	10,135.02

Area		Generation (MW)		Load (MW)	
Number	Name	Orig.	Reduced	Orig.	Reduced
523	GRDA	1,121.08	1,121.08	1,029.49	1029.49
524	OKGE	7,320.33	7,320.33	6,324.73	6,324.73
525	WFEC	1,204.02	1,204.02	1,382.50	1382.50
526	SWPS	5,895.59	5,895.59	5,936.61	5,936.61
527	OMPA	55.72	55.72	666.35	666.35
531	MIDW	124.61	124.61	376.45	376.45
534	SUNC	544.26	544.26	451.60	451.60
536	WERE	6,101.78	6,101.78	6,014.75	6,014.75
539	WEPL	387.51	387.51	678.40	678.40
540	MIPU	1,156.59	1,156.59	2,101.40	2,101.40
541	KACP	4,327.93	4,327.93	3,515.62	3,515.62
542	KACY	574.77	574.77	554.03	554.03
544	EMDE	1,122.64	1,122.64	1,177.49	1,177.49
545	INDN	216.87	216.87	322.44	322.44
546	SPRM	741.80	741.80	784.85	784.85
640	NPPD	3,118.84	3,118.84	3,659.72	3,659.72
645	OPPD	3,273.60	3,273.60	2,972.12	2,972.12
650	LES	262.91	262.91	803.40	803.40
	TOTAL:	52,283.21	52,117.14	53,206.10	52,124.99

Note: The reduced system parameters are used throughout this report unless otherwise noted.

3.3 Basecase Small Signal Stability

Single Machine Infinite Bus (SMIB) analysis was performed on the 2011 basecase, to determine if system contains any significant or unusual local modes of oscillation. These modes are typically an indication of possible discrepancy within dynamic data such as generator models, its associated controls such as exciter, governor, or power system stabilizer (PSS).

The results of SMIB analysis on the basecase revealed that a unit located in Area 515 (SWPA) at bus 505436, ID:1, had a local mode at a frequency of 0.0238 Hz with negative damping ratio of 4.2%. After examination of the unit dynamic data, it was suspected that the exciter output feedback gain K_E (type IEEET1) might have contributed to this negative damping. In order to implement automatic calculation for K_E at the program initialization, K_E was set as zero. Setting parameter K_E to zero initiates an automatic calculation process within the program to derive a suitable value for K_E. Following this modification, the final SMIB analysis results were acceptable. The mentioned generator mode was observed to have a positive damping of 100% at zero hertz frequency.

3.4 Load models

Static load models were added to the dynamic data based on ZIP (constant impedance, constant current, constant power) model. For all SPP areas, the constant current load model was used for the real component of load and constant impedance was used for the reactive component of load. Frequency dependency coefficients of 1%[2] and –1% were assumed for the real and reactive components of the load models, respectively.

3.5 Relay Model Conversion

SPP provided UFLS relay data for its members in the MS Excel program format. The Excel file is referred to as the Control Area Workbook (CAW). The CAW is used by SPP members to document their UFLS relay data, as required by section 7.3 of the SPP Criteria (see Appendix B). Table 3-3 lists the SPP members and shows which members submitted their UFLS relay database.

Table 3-3: SPP Member UFLS Relay Data Submission Status

No	Area Abbreviation	Area Number	Area Name	Data Submitted	%Total SPP Peak Load
1	CELE	502	Cleco Power, LLC	Y	4.7
2	LAFA	503	City of Lafayette, LA	Y	0.9
3	LEPA	504	Louisiana Energy & Power Authority	N	0.4
4	SWPA	515	Southwestern Power Administration	Y	1.7
5	AEPW	520	American Electric Power West	Y	19.4
6	GRDA	523	Grand River Dam Authority	Y	1.9
7	OKGE	524	OG&E Electric Services	Y	11.9
8	WFEC	525	Western Farmers Electric Coop	Y	2.6
9	SWPS	526	Southwestern Public Service Company	Y	11.2
10	OMPA	527	Oklahoma Municipal Power Authority	Y	1.3
11	MIDW	531	Midwest Energy, Inc	Y	0.7
12	SUNC	534	Sunflower Electric Power Corporation	Y	0.8
13	WERE	536	Western Energy, Inc	Y	11.3
14	MKEC	539	Mid-Kansas Electric Company	Y	1.3
15	MIPU	540	Missouri Public Service	Y	3.9
16	KACP	541	Kansas City Power & Light Company	Y	6.6
17	KACY	542	Board of Public Utilities	Y	1.0
18	EMDE	544	Empire District Electric Company	Y	2.2
19	INDN	545	City Power & Light	Y	0.6
20	SPRM	546	City Utilities, Springfield, MO.	Y	1.5
21	NPPD	640	Nebraska Public Power District	Y	6.9
22	OPPD	645	Omaha Public Power District	Y	5.6
23	LES	650	Lincoln Electric System	Y	1.5

As shown in Table 3-3 almost all SPP members provided UFLS relay data. The only member with no UFLS data, area 504, represents about 0.4% of total SPP peak load. Although this area was included in the study, no UFLS data was considered for this area.

[2] E.g., 1% frequency change causes 1% change in load

The submitted relay data included the following relay types:

- Under-frequency load shedding (up to 5 stages with and w/o remote line/generator tripping).
- Over-frequency generator tripping.
- Under-frequency generator tripping.

The submitted CAW's were checked for errors and discrepancies to validate the relay data entries. As part of the validation process, the following issues were examined:

- Invalid bus #'s, load ID's or circuit ID's by comparison to powerflow basecase.
- Duplicate Bus# entries with the same load ID's.
- Unusual under-frequency setpoints ($f \ll 58.7$ or $f \gg 59.3$).
- Unusually long operating times (relay or breaker).
- Issues with shedding ratios such as ratio scale or sum greater than 100%.
- Redundant and conflicting data.
- Buses with no load or generations with relay setting.
- Any required entries that were left blank.

The issues regarding the aforementioned data along with suggestions that could be used to resolve them were submitted. Once the CAW files were validated, a set of Visual Basic macros were developed to extract and format the relay data into text files that are acceptable by TSAT and/or Siemens/PTI PSS/E software.

SPP standard (see Appendix B) regarding the UFLS program requires the under-frequency relay set-points to closely adhere to the following three stages shown in Table 3-4.

Table 3-4: Under frequency Load Shedding Stages Defined by SPP

Stage	Frequency set-point Hz	% Load Shed
1	59.3	10
2	59.0	10
3	58.7	10

This criterion implies that at least 30% of loads in the SPP power system should be allocated for the load shedding scheme to account for the generation/load imbalance of up to 30%. Also, the load shed should be distributed over a minimum of three stages.

The submitted relay data was analyzed for coherence with the SPP UFLS stages. The results are provided in Table 3-5. It should be noted that reported quantities in Table 3-5 only include bus load shedding, thus load shedding due to circuit tripping is not reflected in this table, but considered in the simulations. In actuality, as is noted in a paragraph below, there is more UFLS (load shedding) than reflected in Table 3-5. The extra load shedding results because, per the excel spreadsheet for UFLS, there are direct trips of circuits. These extra circuits that were tripped by UFLS were not identified as to the MW

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load tripped and were not included in Table 3-5. It should also be noted that pick up delay times are not reflected in Table 3-5.

Table 3-5: UFLS relay summary

Load condition		Total load MW	Stage 1: f ≥ 59.3 Hz		Stage 2: 59.3 > f ≥ 59 Hz		Stage 3: f < 59 Hz		Total UF load shedding	
			MW	%	MW	%	MW	%	MW	%
2011 Summer total SPP		53,206	5,722.6	10.8	5,235.5	9.8	6,641.9	12.5	17,600.0	33.1
502	CELE	2,505.3	235.6	9.4	251.3	10.0	213.1	8.5	700.1	27.9
503	LAFA	485.5	3.4	0.7	3.3	0.7	2.5	0.5	9.2	1.9
504	LEPA	225.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
515	SWPA	898.6	38.5	4.3	0.0	0.0	0.0	0.0	38.5	4.3
520	AEPW	10,339.8	1,039.4	10.1	913.2	8.8	1,054.0	10.2	3,006.6	29.1
523	GRDA	1,029.5	149.4	14.5	147.6	14.3	134.6	13.1	431.6	41.9
524	OKGE	6,324.7	1,029.2	16.3	851.7	13.5	859.2	13.6	2,740.2	43.3
525	WFEC	1,382.5	158.6	11.5	183.3	13.3	174.4	12.6	516.3	37.3
526	SWPS[3]	5,936.6	599.5	10.1	505.1	8.5	641.3	10.8	1,745.9	29.4
527	OMPA	666.4	54.7	8.2	64.0	9.6	75.4	11.3	194.0	29.1
531	MIDW[4]	376.5	53.4	14.2	0.0	0.0	29.0	7.7	82.4	21.9
534	SUNC	451.6	58.3	12.9	38.0	8.4	39.0	8.6	135.3	30.0
536	WERE	6,014.8	805.2	13.4	772.8	12.8	937.2	15.6	2,515.2	41.8
539	MKEC	678.4	58.1	8.6	48.8	7.2	85.9	12.7	192.8	28.4
540	MIPU	2,101.4	274.0	13.0	242.8	11.6	294.0	14.0	810.8	38.6
541	KACP	3,515.6	408.3	11.6	420.6	12.0	345.1	9.8	1,174.0	33.4
542	KACY	554.0	47.5	8.6	65.4	11.8	61.0	11.0	173.9	31.4
544	EMDE	1,177.5	124.9	10.6	104.0	8.8	227.8	19.3	456.6	38.8
545	INDN	322.4	2.2	0.7	1.3	0.4	1.4	0.4	4.8	1.5
546	SPRM	784.9	111.7	14.2	75.5	9.6	93.3	11.9	280.6	35.7
640	NPPD	3,659.7	267.2	7.3	305.4	8.3	236.0	6.4	808.6	22.1
645	OPPD	2,972.1	201.8	6.8	239.9	8.1	1,135.8	38.2	1,577.5	53.1
650	LES	803.4	1.7	0.2	1.5	0.2	1.9	0.2	5.1	0.6

Note: To produce this table the submitted relay data was treated as follows: Stage 1: Freq ≥ 59.3 Hz, Stage 2: 59.0Hz ≤ Freq < 59.3 Hz, Stage 3: Freq < 59.0 Hz.

As shown in Table 3-5, the distribution of the relay set-points defined in the CAW closely adhere to the recommended SPP load shedding stages defined in Table 3-4. In summary, the settings and

[3]Dropped load as a result of circuit tripping were included for this member. The circuit tripping as reported by SPP for stage 1, 2 and 3 were 378.3 MW, 181.7 MW and 385.6 MW respectively.

[4] Dropped load as a result of circuit tripping were included for this member. The circuit tripping as reported by SPP for stage 1 was 35.4 MW.

amount of load shed defined in the relay data are resonantly close to the requirement defined in Table 3-4.

A review of the UFLS scheme derived from the above table indicates that:

1- Areas LAFA, LEPA, SWPA, MIDW, INDN, NPPD and LES have scheduled UFLS ratios substantially lower than 30%.
2- However, SPP (combined areas) closely follow the NERC/SPP UFLS standard.

Upon completion of this study the following two pieces of information were reported to PLI.

1- As reported by SPP, a number of its members, including LAFA, INDN, and LES, submitted their UFLS data in percentage of on their total system load instead of the load at each particular bus. This was determined to be the cause for low amount of load shed for these members in Table 3-5. It should be mentioned that the total load for these three members equals about 3% of SPP's total load, which is reasonably small as compared within SPP's overall UFLS program. Therefore it is not anticipated that such a discrepancy alter the results of this study.
2- SWPA and LEPA do not own or operate any UFLS equipment. All UFLS equipment for these two members is operated by other members and is not included in this study.

4 Simulations and Analysis

To study the dynamic behavior of the SPP UFLS scheme, a number of scenarios were designed to create different levels of mismatch between generation and load. To achieve the desired level of mismatch, scenarios were developed by disconnecting a number of imports to SPP and a number of generators to arrive at the target amount of mismatch between load and generation. There were three levels of generation loss considered, namely, 10%, 20% and 30%. Table 4-1 summarizes the amount of generation disconnected in 2011 basecase to achieve the 10%, 20% and 30% generation loss (GL) scenarios.

Table 4-1: The Studied Generation Loss Scenarios

Power Flow Base Case	Case ID	Imports lost (MW)	Gen. tripping (MW)	Total Gen. Lost (MW)
2011	2011_10%	4806.60	550.77	5357.37
	2011_20%	4806.60	5,909.86	10716.46
	2011_30%	4806.60	11,468.92	16275.52

The dynamic response of the SPP power system following 10%, 20% and 30% generation loss was simulated using PLI's TSAT program. In these simulations the following models and assumptions were used:

(1) The reduced power system model of NERC (SPP network only) was used as powerflow basecase.

(2) All converted relays models were incorporated within the simulations.

(3) Loads were modeled by constant current model for active power and constant impedance model for reactive power. Load active power is assumed to reduce by 1% for 1% frequency drop, and load reactive power is assumed to increase by 1% for 1% frequency drop.

(4) Simulations were performed for a period of 20 seconds for all of the scenarios.

Table 4-2 provides a summary of the simulation results for each scenario. The third column is simply the ratio of load shed to the generation lost (percentage of load shed to generation lost) and may be used to identify over shedding cases.

Table 4-2: Simulation result summary for three Scenario Disturbances

Load condition	Scenario ID	100*(Load Shed/Gen. Lost) (%)	Load shed by UFLS relays MW	Minimum load frequency range (Hz)	
				Lower	Upper
2011	2011_10%	0	0	59.5655	59.7412
	2011_20%	51	5,449	58.9549	59.2985
	2011_30%	82	13,384	58.4876	59.1178

It should be noted that the action of AGC (Automatic Generation Control) was not modeled in any of the simulations. Therefore, the frequency response is only due to primary/governor response. The following sections discuss, in detail, the SPP UFLS results for the 10%, 20% and 30% generation loss scenarios the 2011 basecase.

4.1 Analysis of 10% Generation Loss

Selection of Simulation Scenario

The list of SPP generators that are disconnected in the dynamic simulation to achieve 10% generation loss scenario are shown in Table 4-3.

Table 4-3: Scenario ID 2011_10%GS

Generation Shed for Scenario 2011_10%						
No.	**Area#**	**Area Name**	**Bus #**	**Bus Name**	**Gen ID**	**MW**
1	503	LAFA	502435	HARGIS1 13.8	1	49.79
2			502436	HARGIS2 13.8	1	49.79
3	504	LEPA	503301	MRGNCTY4 138.	3	10.49
4	515	SWPA	505404	MALDEN 2 69.0	1	7.00
5			505408	KENNETT2 69.0	1	7.50
6			505414	PARAGLD2 69.0	1	5.50
7			505417	JNSBGEN1 13.8	1	21.00
8			505417	JNSBGEN1 13.8	2	21.00
9			505419	JNSBGEN2 13.8	1	40.00
10			505424	GF #1 1 13.8	1	49.60
11			505426	GF #2 2 13.8	2	49.60
12			505432	SIKGEN 1 13.8	1	235.00
13			505436	POP BLF2 69.0	1	4.50
					Total:	550.77

The sum of the above generation loss (550.77 MW) plus the import loss (4,806.60 MW) accounts for 10% generation loss required for this scenario. It should be noted that not all of the units listed above were originally planned for generator tripping scenarios. However, it was necessary to trip some units beyond those planned in order to avoid local problems.

Simulation Results

Table 4-4 shows area-by-area load shedding as a result of generation loss (10% GS scenario) for the 2011 basecase.

Table 4-4: Load Shedding Summary by Area For Scenario ID 2011_10%GS

Area	Name	Initial Load (MW)	Load Shed (MW)	Final Load (MW)	Load Shed (%)	Initial Gen. (MW)	Gen. Shed Scheduled (MW)	Gen. Shed UFLS (MW)	Final Gen (MW)	Spinning Reserve Used (MW)
502	CELE	1,852	0	1,852	0.0	2,895			3,178	283
503	LAFA	485	0	485	0.0	223	100		136	13
504	LEPA	61	0	61	0.0	47	10		37	1
515	SWPA	899	0	899	0.0	1,941	441		1,662	161
520	AEPW	10,135	0	10,135	0.0	9,460			10,332	872
523	GRDA	970	0	970	0.0	1,121			1,184	63
524	OKGE	6,325	0	6,325	0.0	7,320			7,863	543
525	WFEC	1,383	0	1,383	0.0	1,204			1,289	85
526	SWPS	5,937	0	5,937	0.0	5,896			6,257	362
527	OMPA	666	0	666	0.0	56			59	3
531	MIDW	376	0	376	0.0	125			127	3
534	SUNC	452	0	452	0.0	544			584	39
536	WERE	6,015	0	6,015	0.0	6,102			6,671	569
539	MKEC	678	0	678	0.0	388			419	31
540	MIPU	2,101	0	2,101	0.0	1,157			1,296	140
541	KACP	3,516	0	3,516	0.0	4,328			4,643	315
542	KACY	554	0	554	0.0	575			583	8
544	EMDE	1,177	0	1,177	0.0	1,123			1,151	28
545	INDN	322	0	322	0.0	217			237	20
546	SPRM	785	0	785	0.0	742			827	86
640	NPPD	3,660	0	3,660	0.0	3,119			3,330	212
645	OPPD	2,972	0	2,972	0.0	3,274			3,389	116
650	LES	803	0	803	0.0	263			294	31
							551			
	Import					4,807	4,807			
	Others									
	Total	52,125	0	52,125	0.0	56,923	5,357		55,548	3,983

Note: Spinning reserves used in the last column is equal to final generation (MW) minus generation shed (MW) minus initial generation (MW).

Figure 4-1 shows the monitored SPP load bus frequencies for the 2011 basecase. It can be seen that the frequency does not fall below first stage, 59.3 Hz, of UFLS setting. The system frequency finally stabilizes to approximately 59.76 Hz.

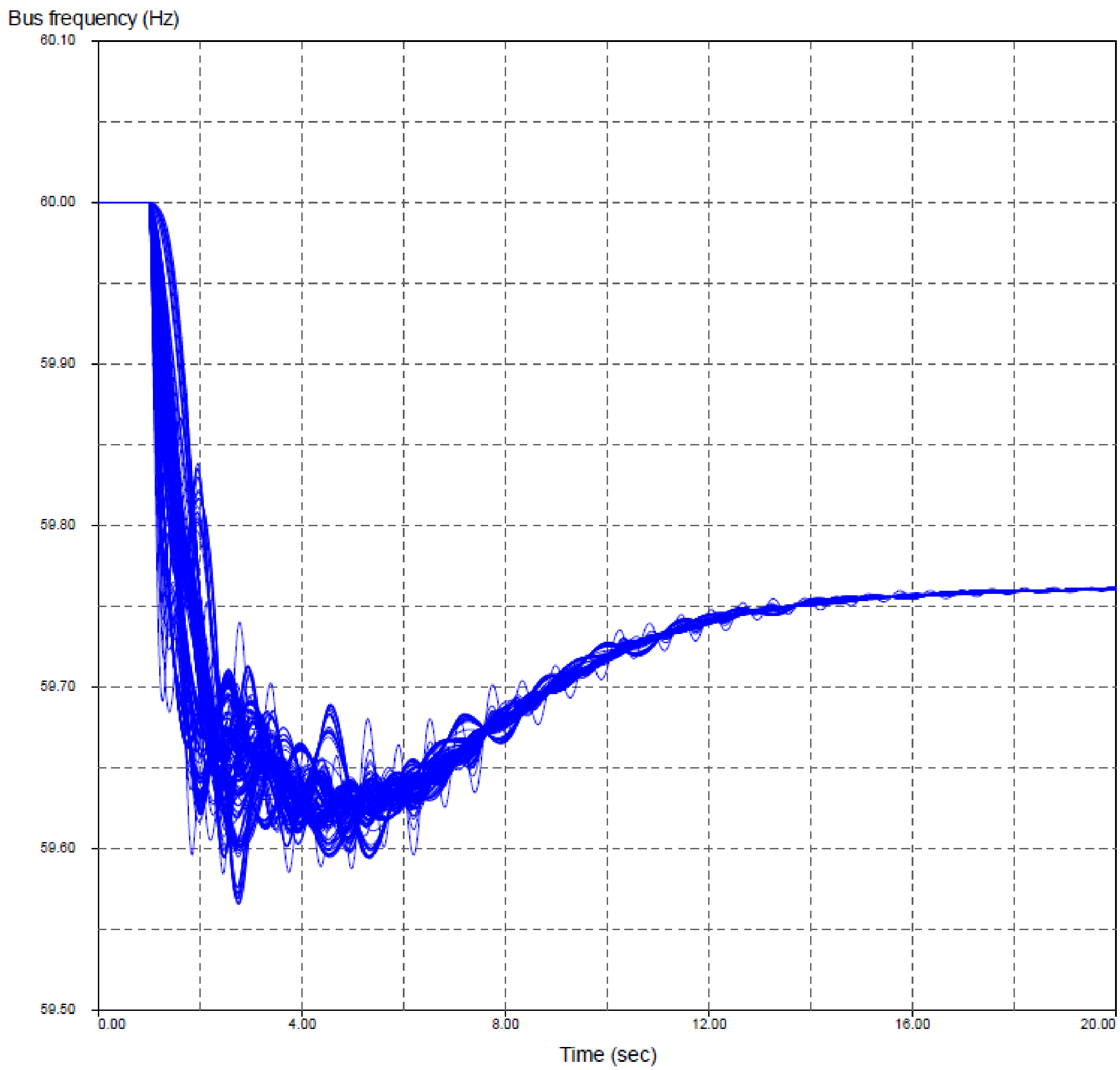

Figure 4-1: Load Bus Frequency Response Scenario 2011_10%GS

Table 4-5 shows a summary of the results for the 2011 basecase 10% generator shedding scenario.

Table 4-5: Load Shedding Summary for Scenario ID 2011_10%GS

TSAT Results (MW)	
Load Shed by UFLS	0
Load Reduction due to Voltage & Frequency	1,145.12
Generation Shed	5,357.37
Spinning Reserve Used	3,982.56

The above results show that for the 10% generation loss scenario, no load is shed by the UFLS scheme. This is attributed to small generation loss compared to the presence of rather large amount of spinning reserve and load relief due to voltage and frequency which caused the system frequency not to drop below the first stage of UFLS scheme.

4.2 Analysis of 20% Generation Loss

Selection of Simulation Scenario

The 20% generation loss scenario is similar to the 10% generation loss scenario described in the previous section with the exception of tripping additional SPP generators to create overall 20% generation loss. Table 4-6 lists the additional units that were disconnected in the dynamic simulations to achieve 20% generation loss scenario.

Table 4-6: Scenario ID 2011_20%GS

Additional Generation Shed for Scenario 2011_20%						
No.	**Area#**	**Area Name**	**Bus #**	**Bus Name**	**Gen ID**	**MW**
1	502	CELE	500205	G1COLUMB 13.8	1	17.70
2	520	AEPW	509394	FLINTCR1 21.0	1	500
3			509404	WELSH1-1 18.0	1	500
4			509406	WELSH3-1 18.0	1	500
5	524	OKGE	514805	SOONER1G 22.0	1	540
6			515225	MUSKOG5G 18.0	1	517
7	526	SWPS	525561	TOLK_1 124.0	1	469.59
8			525562	TOLK_2 124.0	1	540
9	536	WERE	532652	JEC U2 26.0	1	705
10			532722	EEC U2 24.0	1	370
11	541	KACP	542951	HAW G5 1 22.0	5	550
12	640	NPPD	640090	BROKENBG 69.0	1	8.30
					Total:	5,217.59

Simulation Results

The results of time-domain simulation run for 20% generation loss scenario corresponding to the 2011 basecase are summarized in Table 4-7.

Table 4-7: Load Shedding Summary by Area For Scenario ID 2011_20%GS

Area	Name	Initial Load (MW)	Load Shed (MW)	Final Load (MW)	Load Shed (%)	Initial Gen. (MW)	Gen. Shed Scheduled (MW)	Gen. Shed UFLS (MW)	Final Gen (MW)	Spinning Reserve Used (MW)
502	CELE	1,852	177	1,675	9.6	2,895	18		3,224	347
503	LAFA	485	3	482	0.7	223	100		139	16
504	LEPA	61	0	61	0.0	47	10		37	1
515	SWPA	899	39	860	4.3	1,941	441		1,700	200
520	AEPW	10,135	1,039	9,096	10.3	9,460	1,500		8,862	902
523	GRDA	970	149	821	15.4	1,121			1,196	75
524	OKGE	6,325	1,018	5,307	16.1	7,320	1,057		6,840	577
525	WFEC	1,383	128	1,254	9.3	1,204			1,306	102
526	SWPS	5,937	440	5,497	7.4	5,896	1,010		5,250	364
527	OMPA	666	55	612	8.2	56			59	4
531	MIDW	376	53	323	14.2	125			128	3
534	SUNC	452	57	395	12.6	544			585	41
536	WERE	6,015	805	5,210	13.4	6,102	1,075		5,578	552
539	MKEC	678	58	620	8.6	388		142	265	19
540	MIPU	2,101	274	1,827	13.0	1,157			1,323	167
541	KACP	3,516	72	3,444	2.1	4,328	550		4,123	346
542	KACY	554	60	494	10.8	575			585	10
544	EMDE	1,177	125	1,053	10.6	1,123			1,157	34
545	INDN	322	2	320	0.7	217			240	23
546	SPRM	785	112	673	14.2	742			846	105
640	NPPD	3,660	267	3,393	7.3	3,119	8		3,348	238
645	OPPD	2,972	297	2,676	10.0	3,274			3,413	139
650	LES	803	2	802	0.2	263			299	37
							5,910			
	Import					4,807	4,807			
	Others		187							
	Total	52,125	5,419	46,893	198.8	56,923	10,716		50,506	4,299

Note: In the above table, the row identified as "Others" includes load shedding in areas EES (351) and WECC (999).

The frequency response of the load buses for the 20% generation loss scenario is shown in Figure 4-2. It can be seen that the frequency falls below first stage and second stages of UFLS setting (59.3 and 59.0 Hz respectively) and recovers to approximately 59.73 Hz.

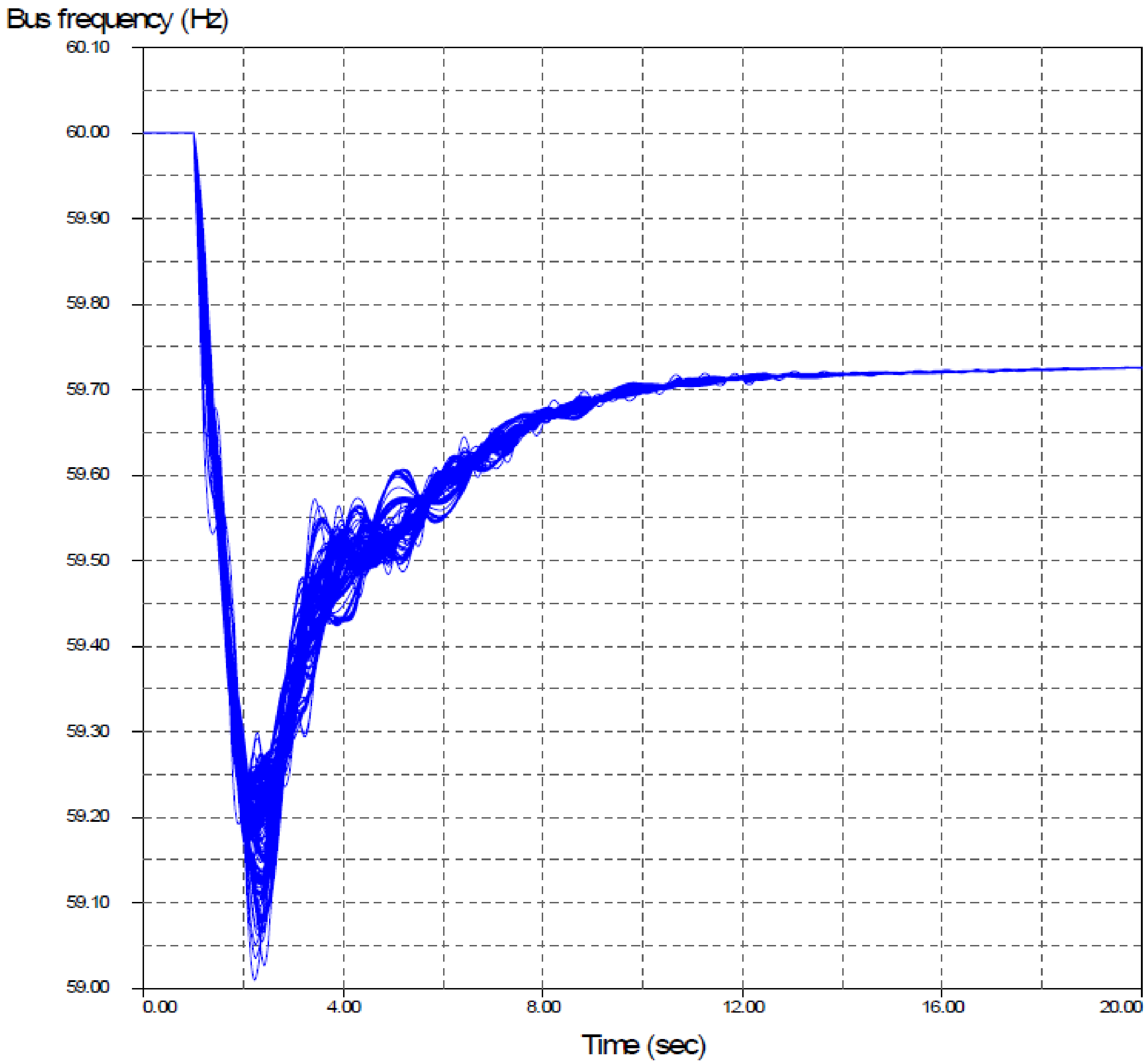

Figure 4-2: Load Bus Frequency Response for Scenario 2011_20%GS

Summary of the result for 20% generation loss scenario is shown in Table 4-8.

Table 4-8: Load Shedding Summary for Scenario ID 2011_20%GS

TSAT Results (MW)	
Load Shed by UFLS	5,232.15
Load Reduction due to Voltage & Frequency	845.32
Generation Shed	10,716.47
Spinning Reserve Used	4,299.16

4.3 Analysis of 30% Generation Loss

Selection of Simulation Scenario

The 30% generation loss scenario is similar to the 20% generation loss scenario described in the previous section with the exception of tripping of additional SPP generators to create the 30% generation loss. Table 4-9 lists the additional units that were disconnected in the dynamic simulations to achieve 30% generation loss.

Table 4-9: Scenario ID 2011_30%GS

Additional Generation Shed for Scenario 2011_30%						
No.	**Area#**	**Area Name**	**Bus #**	**Bus Name**	**Gen ID**	**MW**
1	502	CELE	501811	G1RODEMR 22.0	1	310.00
2			501910	G1 ACAD 18.0	1	200.00
3	515	SWPA	505452	NFK #1 1 13.8	1	10.00
4			505454	NFK #2 1 13.8	2	10.00
5			505462	BSH #1 1 13.8	1	36.60
6			505464	BSH #2 1 13.8	2	36.60
7			505466	BSH3&4 1 13.8	3	36.60
8			505466	BSH3&4 1 13.8	4	36.60
9			505468	BSH5&6 1 13.8	5	41.20
10			505468	BSH5&6 1 13.8	6	41.20
11			505470	BSH7&8 1 13.8	7	41.20
12			505470	BSH7&8 1 13.8	8	41.20
13			505476	TBR1&2 1 13.8	1	49.60
14			505476	TBR1&2 1 13.8	2	49.60
15			505478	TBR3&4 1 13.8	3	49.60
16			505478	TBR3&4 1 13.8	4	49.60
17	520	AEPW	506749	ESTGAS1 18.0	1	100.00
18			509392	ARSHILL3 18.0	G2	100.00
19			509409	WILKE3-1 22.0	1	200.00
20			511842	RSS1-1 24.0	1	407.87
21	523	GRDA	512686	SALINA 5 161.	1	37.03
22			512686	SALINA 5 161.	2	37.03
23			512686	SALINA 5 161.	3	37.03
24	524	OKGE	514859	MUSTNG4G 20.9	1	193.00
25			515226	MUSKOG6G 24.0	1	520.00
26	525	WFEC	520998	MORLND3 18.0	1	140.00
27			521110	ORME1 13.8	1	60.00
28	526	SWPS	523431	SIDRCH 2 69.0	1	20.00
29	527	OMPA	529251	OMPONCA2 69.0	3	11.07
30	531	MIDW	530555	COLBY 3 115.	01	5.02
31			530555	COLBY 3 115.	02	0.67
32			530595	SMOKY_WND 0.57	01	9.00

Additional Generation Shed for Scenario 2011_30%						
No.	**Area#**	**Area Name**	**Bus #**	**Bus Name**	**Gen ID**	**MW**
37	534	SUNC	531459	S2 GEN 1 13.8	2	90.00
38	536	WERE	532663	LEC U5 24.0	1	353.43
39	539	MKEC	539677	MULGREN1 13.8	3	91.00
40	540	MIPU	541165	S.HARP#1 13.8	1	105.00
41			541166	S.HARP#2 13.8	2	105.00
42	541	KACP	542952	MONTG1 1 22.0	1	120.00
43			542953	MONTG2 1 22.0	2	120.00
44	542	KACY	546698	QGEN2 1 15.0	1	124.37
45	544	EMDE	547648	OZD312 1 4.60	1	4.00
46			547648	OZD312 1 4.60	2	4.00
47			547648	OZD312 1 4.60	3	4.00
48			547648	OZD312 1 4.60	4	4.00
49			547658	S4G439 1 18.0	1	199.94
50	545	INDN	548806	BLUVLY 69.0	4	46.81
54	546	SPRM	549890	SWPS GEN#1 120.0	1	178.00
55	640	NPPD	640019	SHELDN1G 13.8	1	114.00
56			640020	SHELDN2G 13.8	2	129.00
57			640022	BPS GT1G 13.8	1	78.00
58			640154	CRETE G 34.5	1	15.70
59			641086	EGY CTRG 13.8	1	84.00
60			642067	PLATTE1G 13.8	1	104.40
61	645	OPPD	645001	FT CAL1G 22.0	1	505.00
62	650	LES	650092	ROKEBY2G 13.8	2	62.00
					Total:	5,559.03

Simulation Results

The result of time domain simulation runs for 30% generation loss scenario is summarized in Table 4-10.

Table 4-10: Load Shedding Summary by Area For Scenario ID 2011s_30%GS

Area	Name	Initial Load (MW)	Load Shed (MW)	Final Load (MW)	Load Shed (%)	Initial Gen. (MW)	Gen. Shed		Final Gen (MW)	Spinning Reserve Used (MW)
							Scheduled (MW)	UFLS (MW)		
502	CELE	1,852	348	1,504	18.8	2,895	528		2,554	187
503	LAFA	485	7	479	1.4	223	100		132	9
504	LEPA	61	0	61	0.0	47	10		37	0
515	SWPA	899	39	860	4.3	1,941	970		1,048	77
520	AEPW	10,135	1,953	8,182	19.3	9,460	2,308		7,354	202
523	GRDA	970	297	673	30.6	1,121	111		1,046	36
524	OKGE	6,325	1,855	4,470	29.3	7,320	1,770		5,859	309
525	WFEC	1,383	342	1,041	24.7	1,204	200		1,052	48
526	SWPS	5,937	1,362	4,575	22.9	5,896	1,030		5,078	212
527	OMPA	666	119	548	17.8	56	11		46	2
531	MIDW	376	53	323	14.2	125	15		110	0
534	SUNC	452	95	357	21.0	544	90		481	26
536	WERE	6,015	1,580	4,435	26.3	6,102	1,428		5,001	328
539	MKEC	678	176	503	25.9	388	91	142	163	8
540	MIPU	2,101	811	1,291	38.6	1,157	210		1,033	87
541	KACP	3,516	569	2,947	16.2	4,328	790		3,745	208
542	KACY	554	173	381	31.3	575	124		455	4
544	EMDE	1,177	229	949	19.4	1,123	216		924	18
545	INDN	322	3	319	1.1	217	47		182	12
546	SPRM	785	187	598	23.9	742	178		613	49
640	NPPD	3,660	777	2,882	21.2	3,119	533		2,732	146
645	OPPD	2,972	781	2,192	26.3	3,274	505		2,863	95
650	LES	803	3	800	0.4	263	62		224	23
							11,469			
	Import					4,807	4,807			
	Others		294							
	Total	52,125	12,052	40,367	434.8	56,923	16,276		42,733	2,085

Note: In the above table, the row identified as "Others" includes load curtailment in areas EES (351) and WECC (999).

The frequency response of the load buses for the 30% generation loss scenario is shown in Figure 4-3. It can be seen that the frequency falls approximately to 58.5 Hz activating the third stage of UFLS and is stabilized to approximately 59.75 Hz.

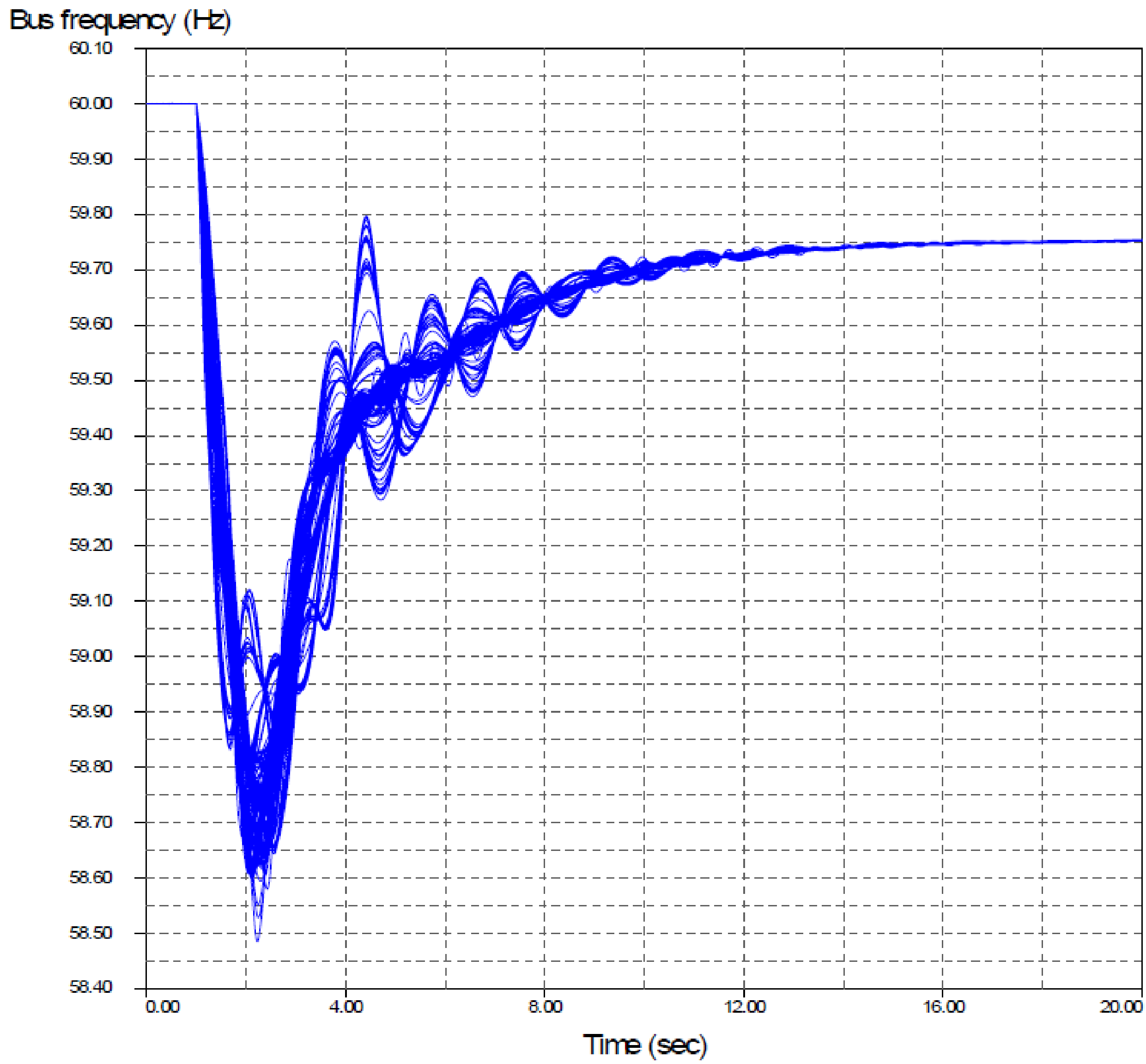

Figure 4-3: Load Bus Frequency Response for Scenario 2011_30%GS

Summary of the results for the 30% generation loss scenarios are shown in Table 4-11.

Table 4-11: Load Shedding Summary for Scenario ID 2011_30%GS

TSAT Results (MW)	
Load Shed by UFLS	11,757.87
Load Reduction due to Voltage & Frequency	393.49
Generation Shed	16,275.63
Spinning Reserve Used	2,085.14

30% Generation Loss Scenario Assuming 10% Over Shedding

Since the exact amount of load available for the UFLS scheme is practically difficult to estimate, SPP is concerned that an over-frequency situation, due to over shedding, may arise under the worst condition of mismatch between load and generation (e.g. 30% generation loss). To address this concern, it was decided to repeat the 30% generation loss scenario, similar to the previous section, with the exception of simulating additional load shedding by suddenly ramping down the load by 10%. Figure 4-4 shows the frequency of the monitored SPP generators for the 30% generation loss scenario for 2011 basecase with an additional 10% load shed. The maximum frequency reached is approximately 60.40 Hz. This frequency overshoot is not expected to activate any generator over-speed protection scheme.

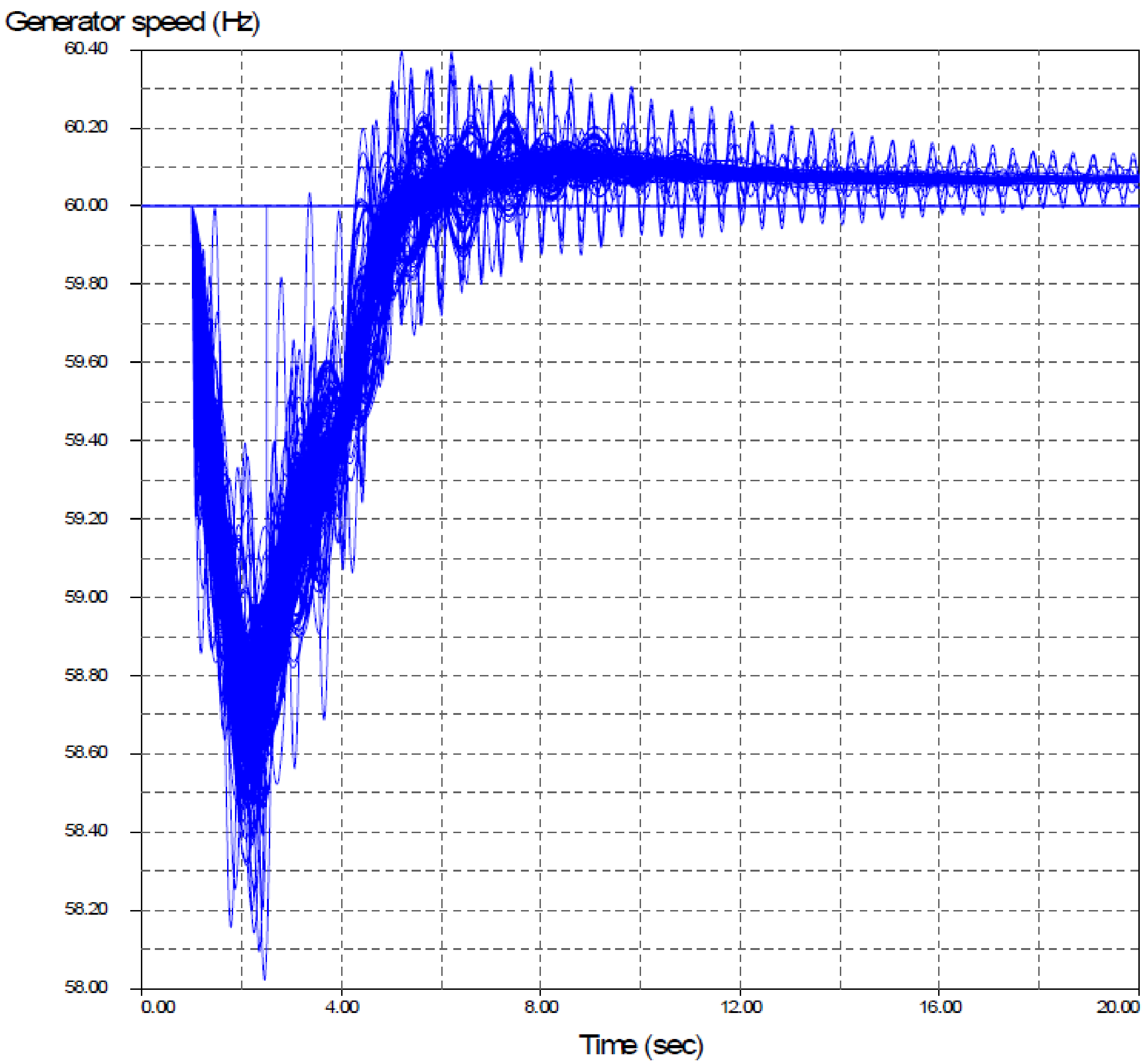

Figure 4-4: Generator Frequency for Scenario 2011_30%GS with Additional 10% Load Shedding

30% Generation Loss Scenario Assuming 15% Over Shedding

A similar simulation as described in the previous section was carried out but assuming 15% over-shedding[5]. In this case, the maximum over-frequency is approximately 60.71 Hz depicted in Figure 4-5. It is not expected that such a frequency could cause generator over-speed protection to trip any units; however, it is recommended that SPP members investigate if any of their units have over-speed protections with settings close to the observed over-frequency condition.

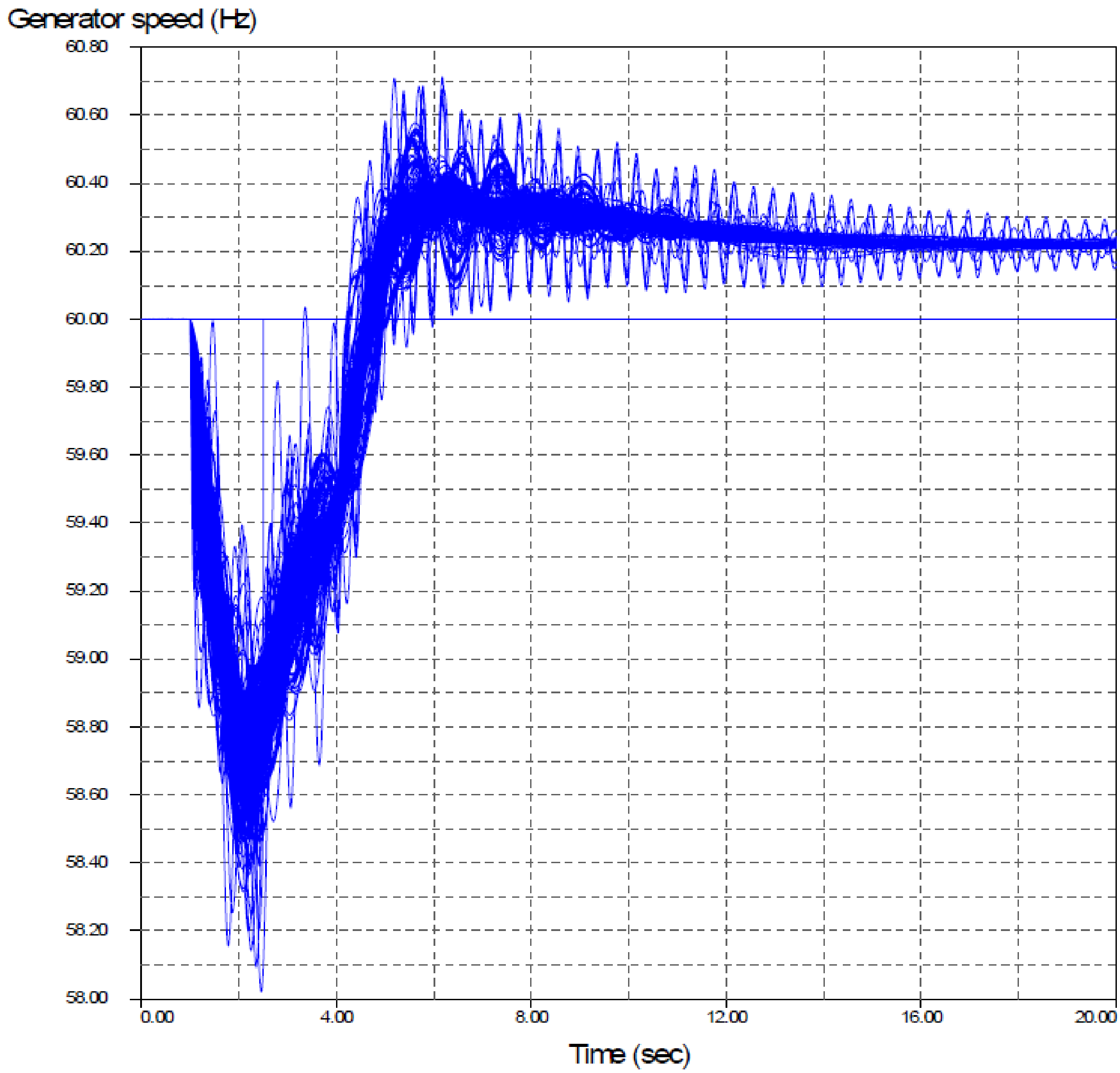

Figure 4-5: Generator Frequency for Scenario 2011_30%GS with Additional 15% Load Shedding

[5] In addition to the list of the disconnected generators under 30%generator loss scenario, generator 529252, ID:1 with 29.7 MW output was also disconnected for this study to improve system-wide dynamical performance.

30% Generation Loss Scenario with 45% SPP-wide load Shedding

In order to further investigate system performance subjected to excessive load shed, the effect of 30% generation loss[6] with 45% system-wide load shed throughout SPP is investigated[7]. The load shed is implemented by reducing the SPP load to -45% of its value over a period of 0.1 seconds. The simulation results indicated that the maximum over-frequency is approximately 61.5 Hz as depicted in Figure 4-6. It is not expected that this frequency will cause generator over-speed protection to trip any units.

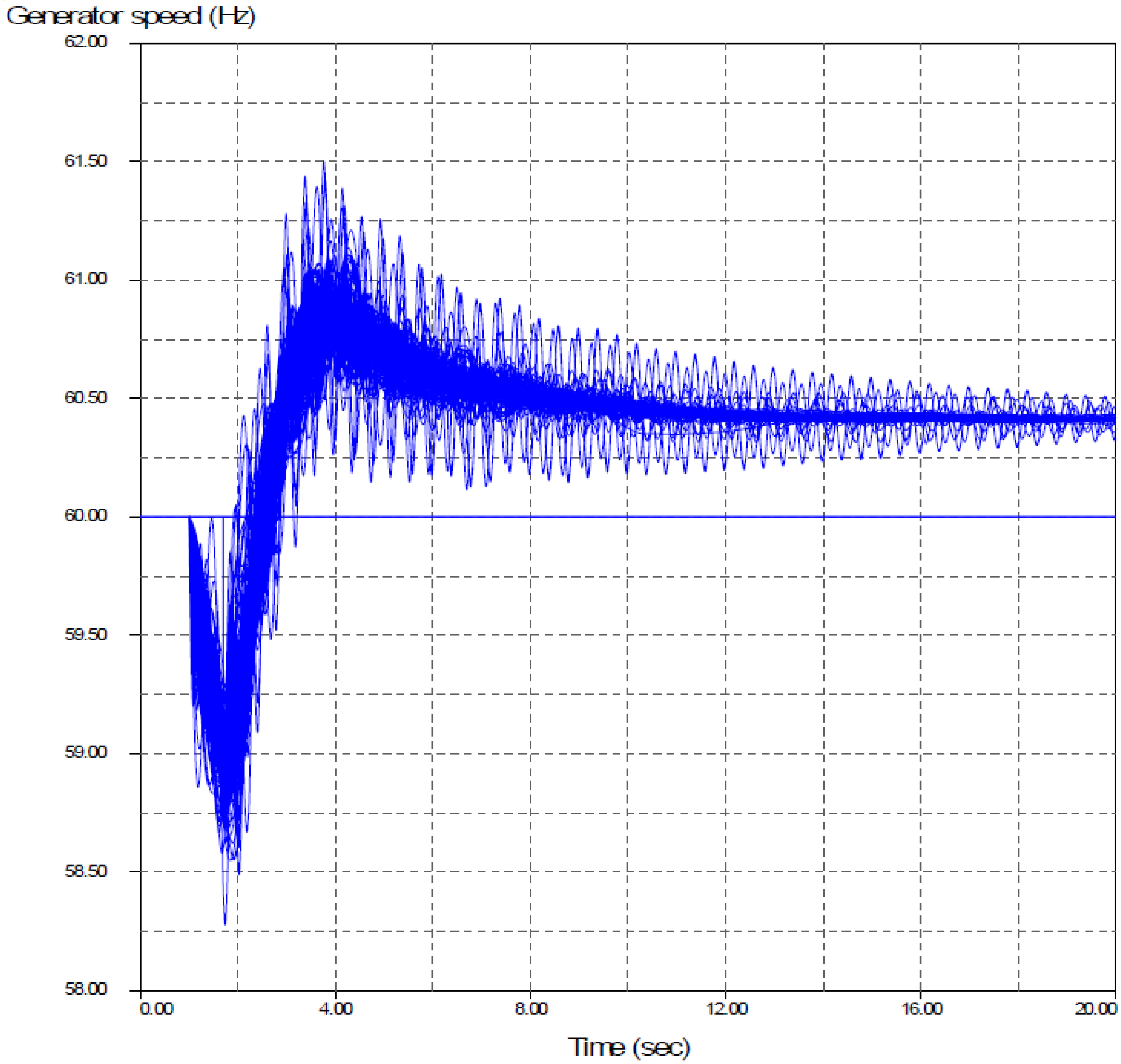

Figure 4-6: Generator Frequency for Scenario 2011_30%GS with 45% SPP Load Shedding

[6] In addition to the list of the disconnected generators; i.e. 30% generator loss scenario, generator located at bus 529252, ID:1 with 29.7MW output and generator located at bus 650001, ID:1 with 23 MW were also disconnected.
[7] For sake of this scenario the effect of UFLS relays were not considered

Study of under-voltage inhibit setting on UFLS scheme

In order to determine the effect of under-voltage inhibit on the UFLS scheme operation, it is required to identify UFLS relays with bus voltages with equal or less than inhibit threshold value of 85%. For this purpose, bus voltages of the UFLS relays that operated during 30% generation deficiency scenario were monitored and relays with bus voltages equal or below the inhibit value of 0.85 pu prior to relay operation were identified.

The simulation progress report indicated that a total of 907 UFLS relays operated during 30% gen loss scenario. For these relays their bus voltages prior to the moment that they operated were monitored, and buses with voltage magnitudes equal or below the inhibit threshold were identified. These buses were reported in the following table.

Table 4-12: UFLS relays affected by voltage inhibit

AREA	Bus		Pre-operation Voltage (pu)	Affected Load (MW)	Note
	#	Name			
515 SWPA	505408	KENNETT2 69.0	0.00	38.5	Bus voltage was reduced to zero as a result of generator shed.
544 EMDE	547489	BRN413 5 161.	0.77	25.8	
	547497	RVS438 5 161.	0.82	21.5	
	547587	STR370 2 69.0	0.84	5.2	
	547604	BHJ415 2 69.0	0.81	11.0	
			Total:	102.0	

Note: Bus 505408 voltage was dropped to zero at 1.0 seconds, before the first UFLS relay operation at 1.484 seconds; part of 30% gen shed.

The voltages for buses 547489 (red), 547497 (blue), 547587 (green), 547604 (brown) are provided below.

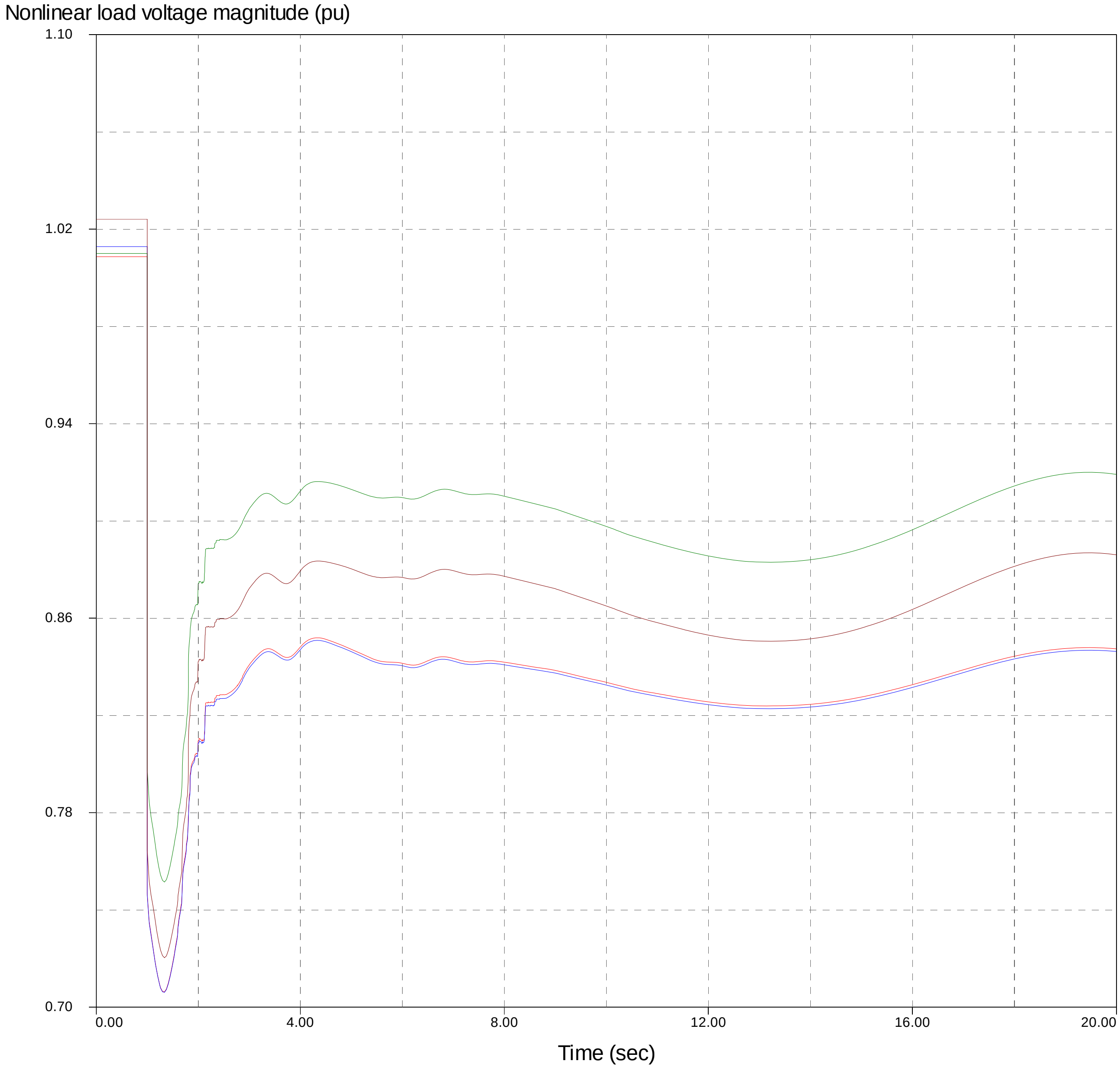

Figure 4-7: Inhibit Bus Voltages for Scenario 2011_30%GS

The above results indicated that the load shedding scheme that could be affected by the UFLS inhibit function is 102 MW. This amount accounts for less than 1% of the load dropped by UFLS scheme (11,758 MW). Therefore, as confirmed by simulation, under-voltage inhibit setting equal to 85% and below has negligible impact on the SPP established UFLS program.

Study of V/Hz (Magnetic flux)

As a part of UFLS evaluation, V/Hz for all SPP generators at generator terminal bus and/or generator step-up (GSU) transformer high-side bus was studied. This study is performed to assess generators and transformers magnetic flux during 30% generation loss scenario. The actual magnitude of magnetic flux in generator stator or transformer core is difficult to measure, however it can be quantified in terms of per unit V/Hz, since the operating magnetic flux in electric machineries is proportional to the ratio of the operating voltage to the electrical frequency. Therefore, V/Hz provides a measure of generator stator and transformer core magnetic flux. Excessive magnetic flux in transformer or generator results in thermal damages to generator and GSU transformer. These damages are typically cumulative. These damages include, but are not limited to, generator stator and GSU transformer core damage, and degradation of insulation material. Excessive magnetic flux may even cause unwanted operation of protection system. The objective of study is to identify generator terminal or GSU transformer high-side buses for which V/Hz exceeds stipulated values of 1.18 pu for longer than two seconds cumulatively, or 1.1 pu for longer than 45 seconds cumulatively for the simulated event of 30% generation loss scenario.

Following a preliminary review of the generators' V/Hz, the following observations were made.

- Generator terminal bus 640090 V/Hz exceeded 1.18 pu prior to the 30% generation loss simulated event.
- Generator terminal buses 514897, 5244485 and 541151 V/Hz exceeded 1.1 pu prior to the 30% generation loss event and as the system reaches steady state following the simulated event.

The details pertaining to these generators are summarized below. The V/Hz in per unit at each generator terminals prior to the simulated event and at steady state after the simulated event are provided. The generator terminal voltage and GSU transformer high voltage side in per unit prior to the simulated event are also provided.

Table 4-13: Generators with large V/Hz

Area	Bus no.	Bus name	Generator		V/Hz (pu)		Voltage (pu)		Note
			ID	Base MVA	Initial	Final	GSU Xfrm HV	Gen. terminal	
524 OKGE	514897	SMITH 1S 13.8	1	55.5	1.12	1.12	1.02	1.12	Generator terminal voltage is initially 1.12 pu. The three-winding GSU transformer has relatively large tertiary impedance.
526 SPS	524485	CAPROCK_WND134.5	DA	40.4	1.15	1.17	1.03	1.16	Synchronous condenser.
540 MIPU	541151	SIBLEY#3 22.0	3	451	1.15	1.15	1.02	1.15	Generator terminal voltage is initially 1.15 pu. The GSU transformer impedance is substantially large (24% on generator basis).
640 NPPD	640090	BROKENBG 69.0	1	1	1.23	1.03	1.04	1.23	Generator terminal voltage is initially 1.23 pu. Suspicious generator base MVA; 1MVA? The powerflow results indicate that generator injects 8.3 MW

Review of the above information indicated that the observed initial high V/Hz values for the above mentioned fours generators are contributed to the generator terminal voltages exceeding 1.1 pu prior to the simulated event.[8] In addition, inaccuracy of system data, such as generator base MVA or GSU transformer impedance, could have contributed to the observed generator terminal voltage magnitudes. Since the observed V/Hz for these generators is partially contributed to inaccurate data, no reasonable conclusion can be made from the observed responses of these generators. Thus, these four generators were excluded from V/Hz study.

The plots of generator V/Hz are provided in Figure 4-8. As shown in this figure no generator V/Hz response exceeds 1.18 pu; however, a number of generators' V/Hz response exceed 1.1 pu; however, the cumulative times for these generators are reasonably below 45 seconds.

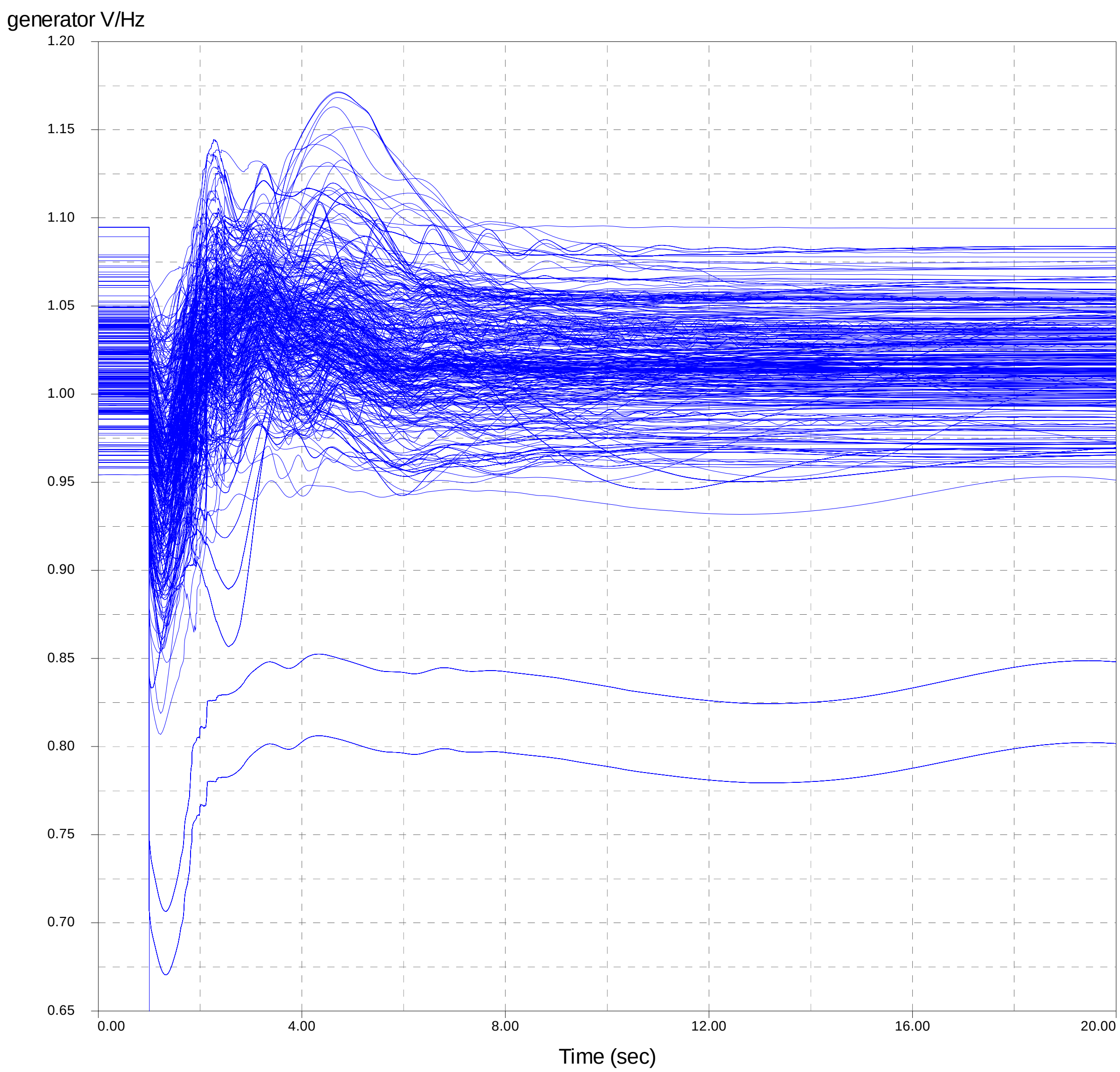

Figure 4-8: Generators V/Hz for 30%_GS

[8] It was noticed that generators 514897, 524485 and 541151AVRs were set to control GSU high voltage bus magnitude.

Study of Effect of Delay in Operation of (UFLS) Relays

In order to study load shedding sensitivity versus relay pickup time setting, the 30% generation drop scenario was simulated with UFLS scheme relays' pickup time adjusted to 30 and 40 cycles, and breaker times adjusted to 6 cycles. In addition all SPP generators were equipped with under-frequency protection scheme. This scheme was adjusted according to PRC-006-SPP-01 characteristic curve.[9] This study develops an insight into the UFLS scheme delay sensitivity by investigating the effect of system-wide UFLS trip time setting. Generally speaking, under-frequency protection at the generator must not operate for disturbances successfully managed by UFLS scheme. Thus the number of the disconnected generator provides an indication UFLS scheme sensitivity to relay pickup time.

30 Cycles Delay

The simulation results for 30% generation loss event with UFLS scheme relays' pickup time adjusted to 30 cycles and breaker times adjusted to 6 cycles, and generators equipped with under-frequency protection are provided below. As the results indicated, the system remains reasonably secure.

[9] This characteristic was implemented using a UDM (user-defined model) for each generator. The implementation is based on monitoring of weighted accumulated time for generator frequencies below 59.3 Hz. This accumulated time is reset for generator frequency above 59.3 Hz. The generator under-frequency protection scheme disconnects the generator once the generator frequency versus weighted accumulated time breaches the under-frequency characteristic requirement. The accumulated time is updated and adjusted by a weighting factor. This weighting factor is a function of generator speed and is adjusted based on under-frequency characteristic requirement.

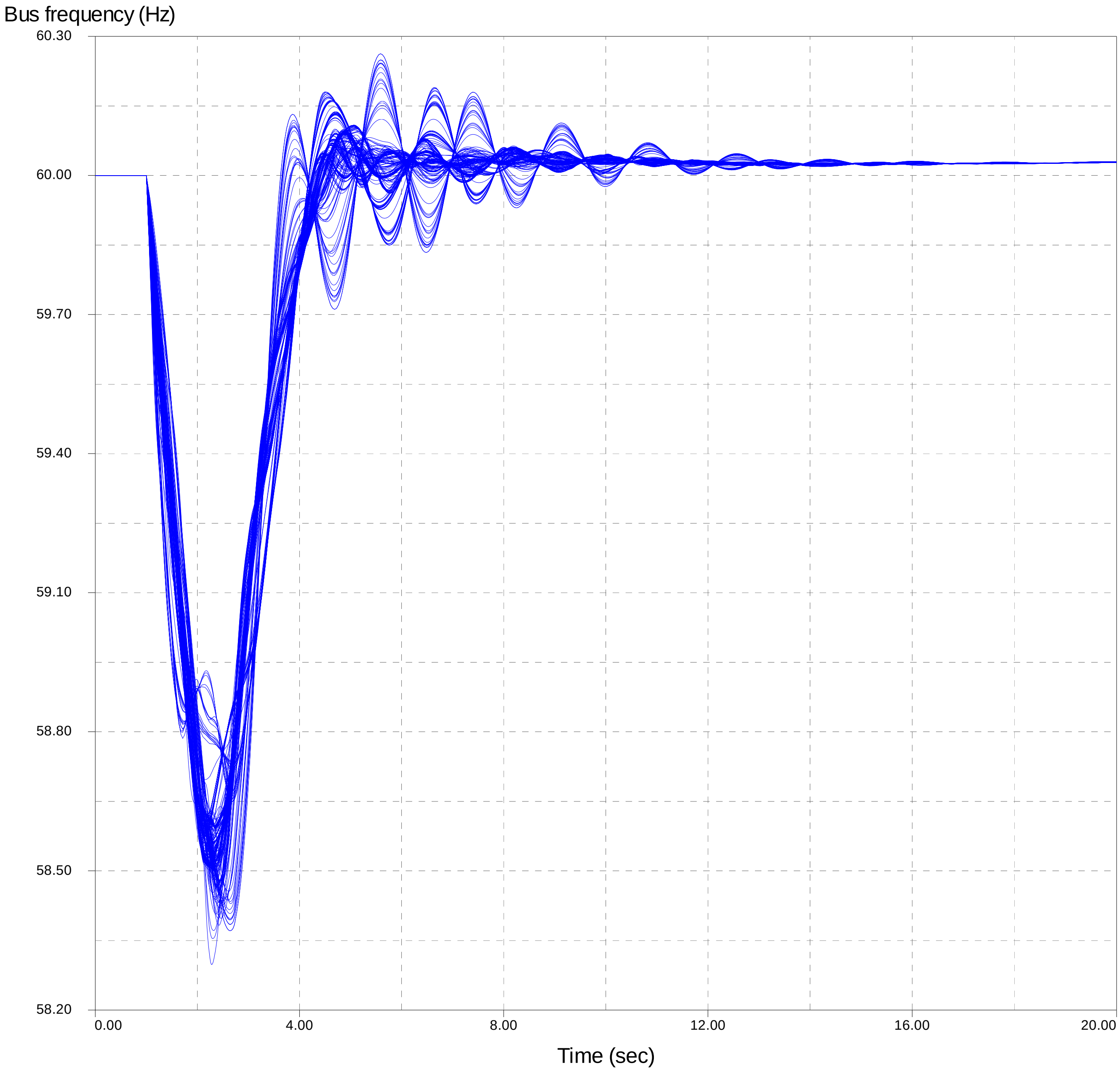

Figure 4-9: Load bus Frequency for Scenario 2011_30%GS with 30 cycles delay

Powertech Labs Inc. 12388 – 88th Avenue Surrey, British Columbia Canada V3W 7R7 Tel: (604) 590-7500 Fax: (604) 590-6656 www.powertechlabs.com

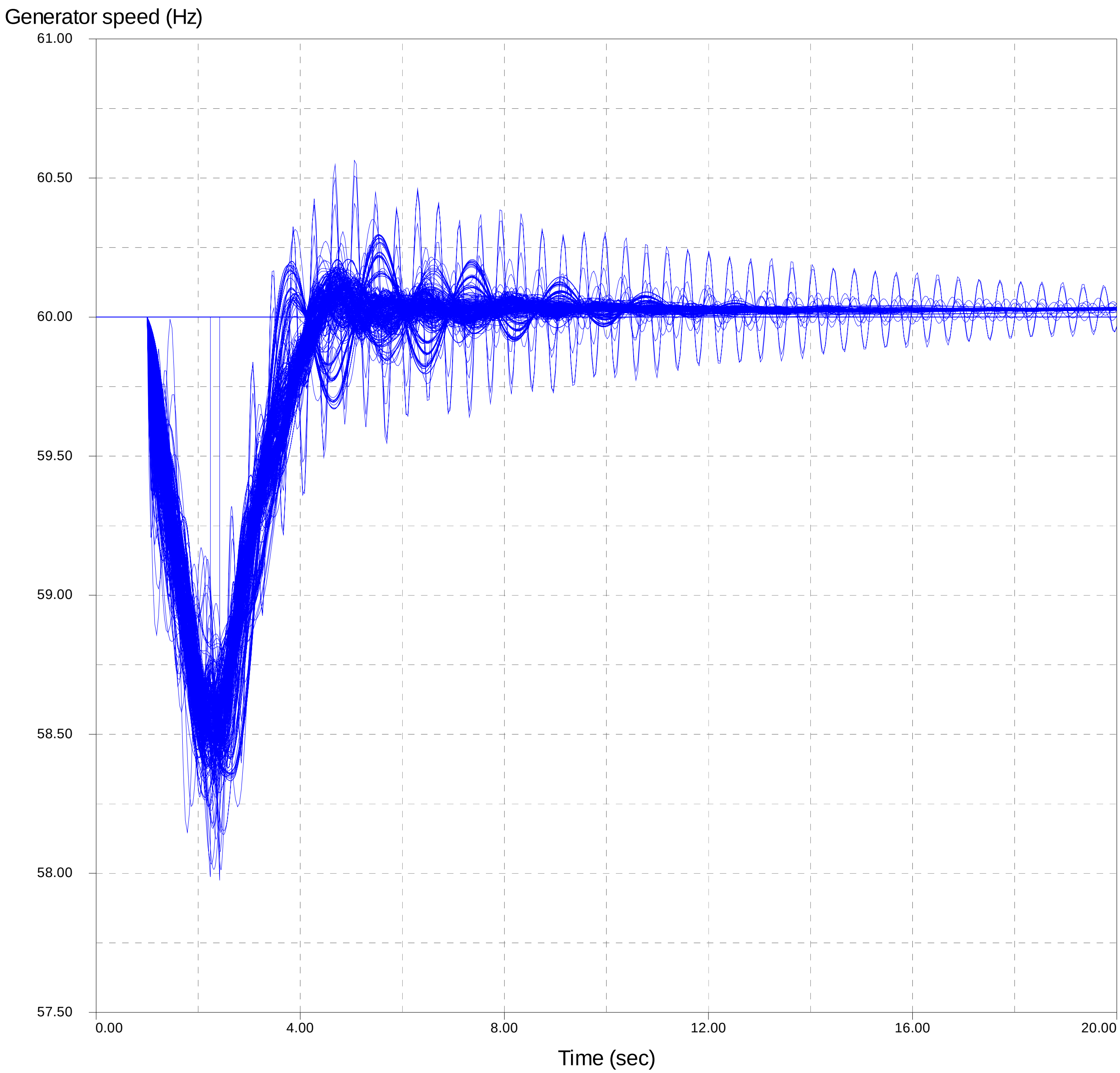

Figure 4-10: Generator Frequency for Scenario 2011_30%GS with 30 cycles delay

The simulation results indicated that the generator under-frequency protection disconnected two generators (640026, 659134).

Table 4-14: Generators tripped by under-frequency requirement for 30-cycle delay

Generation Shed during 30-cycles delay scenario						
No.	**Area#**	**Area Name**	**Bus #**	**Bus Name**	**Gen ID**	**MW**
1	640	NPPD	640026	AINSWD1W 0.60	1	12.00
2			659134	SIDNEY 4 230.	1	20.00
					Total:	32.00

In addition it was observed that two generators performance became relatively close to under-frequency requirement (640016, 640401). In order to develop a better understanding, a comparative study between a tripped generator (640026) and a generator with close to tripping performance (640016) was conducted. The results of the comparative study are provided in Figure 4-11. The frequency speed response for generators 640016 (red) and 640026 (blue) are depicted below.

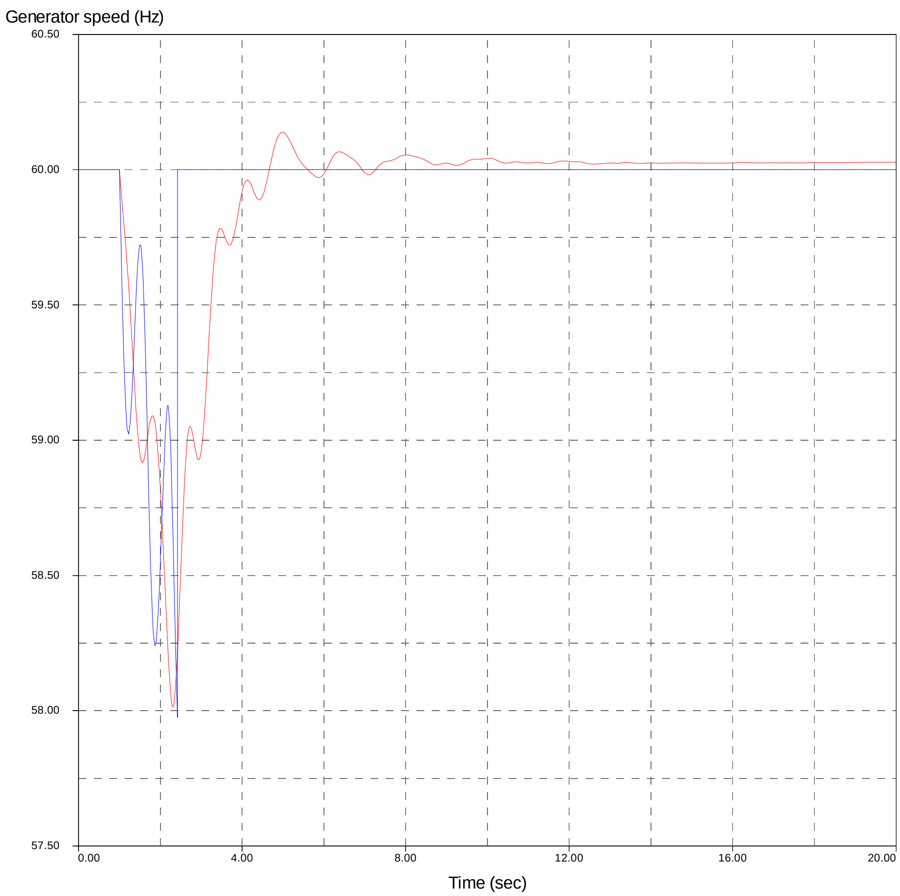

Figure 4-11: Generators 640016 and 640026 Frequency responses for 30 Cycles delay

The plots of generator speed versus weighted accumulated time for the two generators are provided in Figure 4-12. The generator under-frequency requirement curve is also shown overlaid in black. As shown in this figure, generator 640026 (blue) frequency response intersects with generator under-frequency protection curve; however, generator 640016 (red) frequency response does not intersect with the generator under-frequency protection curve. As under-frequency requirement were implemented for all SPP generators, generator 640026 was disconnected at the moment its frequency response intersects the under-frequency requirement curve.

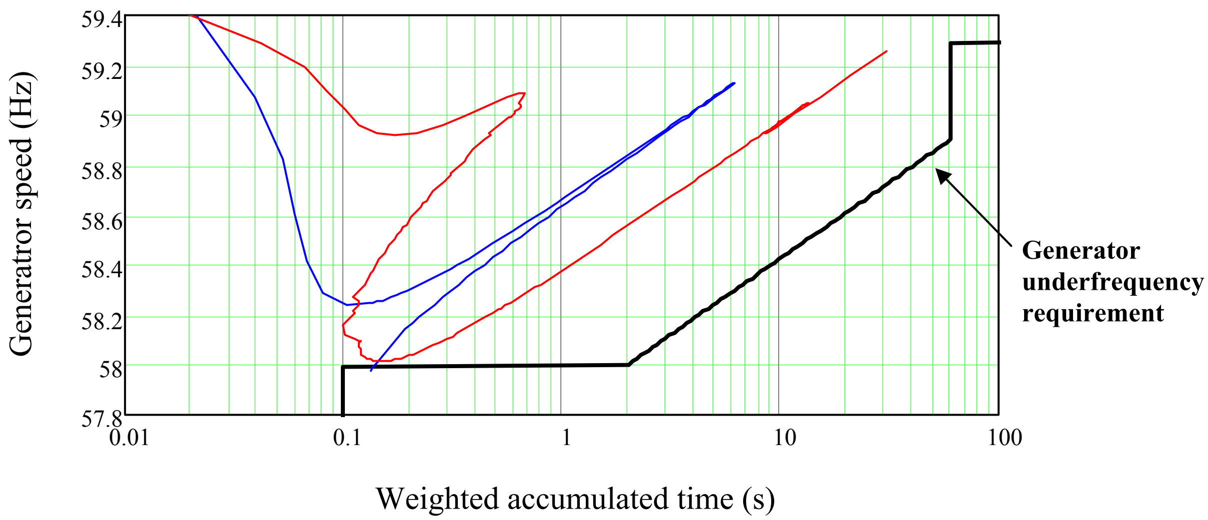

Figure 4-12: Generators 640016 and 640026 Under-frequency responses for 30 Cycles delay

As a part of UFLS evaluation, V/Hz for all SPP generators for this scenario was studied. The objective of this was to identify generators for which V/Hz exceeds 1.18 pu for longer than two seconds cumulatively, or exceeds 1.1 pu for longer than 45 seconds cumulatively for simulated event of 30% generation scenario. The plots of generator V/Hz are depicted below. As shown in this figure no generator V/Hz exceeds 1.18 pu; however a number of generators V/Hz exceeded 1.1 pu.

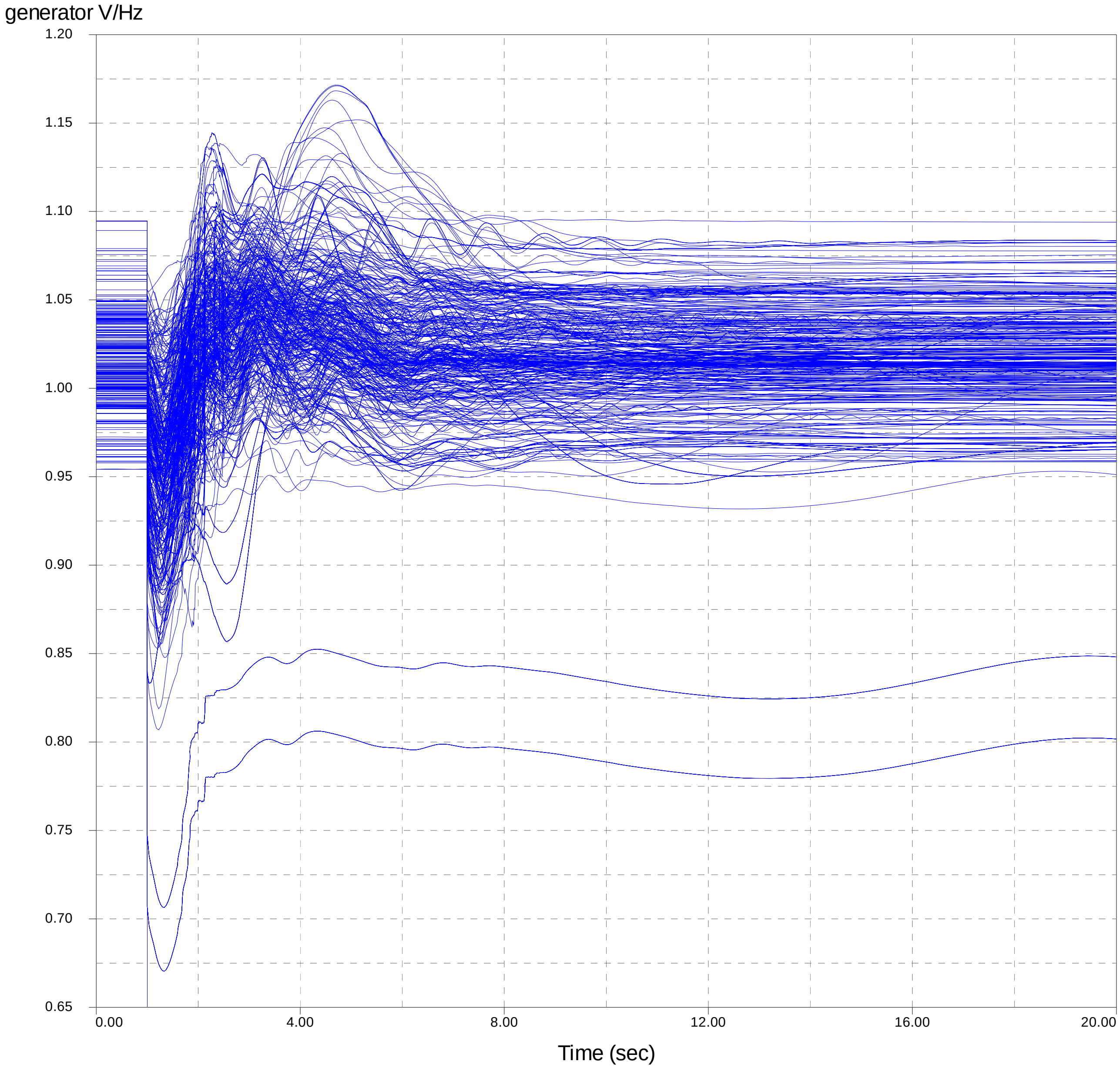

Figure 4-13: Generators V/Hz for 30%_GS with 30 Cycles Delay

The simulation results indicated that 33 generators V/Hz response exceeded 1.1 pu; however, the calculated cumulative times for generators' V/Hz are considerably less than 45 seconds. The maximum calculated cumulative time was 3.8 seconds for generator 506754.

40 Cycles Delay

The simulation results for 30% generation loss event with UFLS scheme relays' pickup time adjusted to 40 cycles and breaker times adjusted to 6 cycles, and generators equipped with under-frequency protection are provided below. As the results indicated, the system remains reasonably secure.

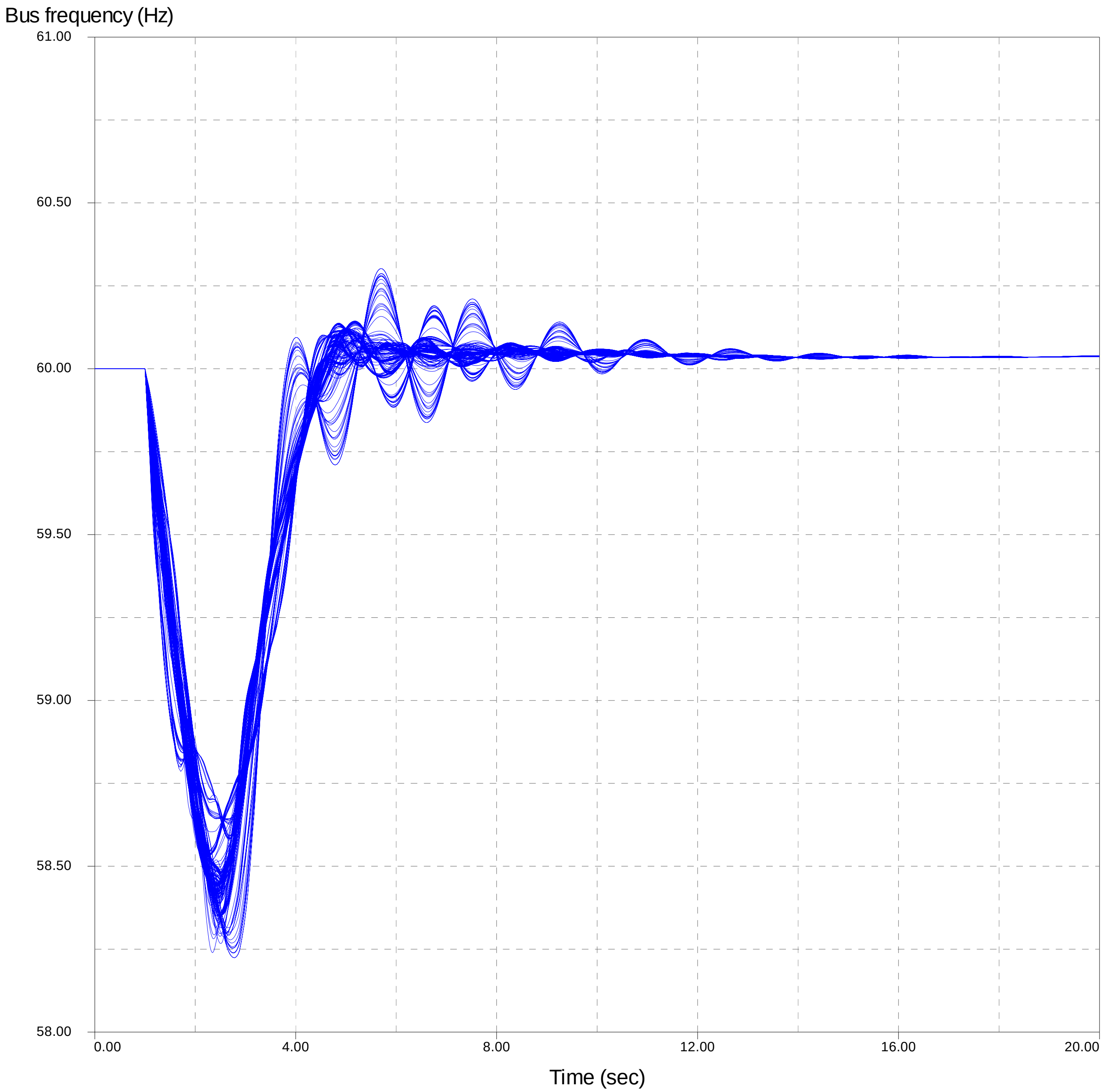

Figure 4-14: Load Buses Frequency for Scenario 2011_30%GS with 40 cycles delay

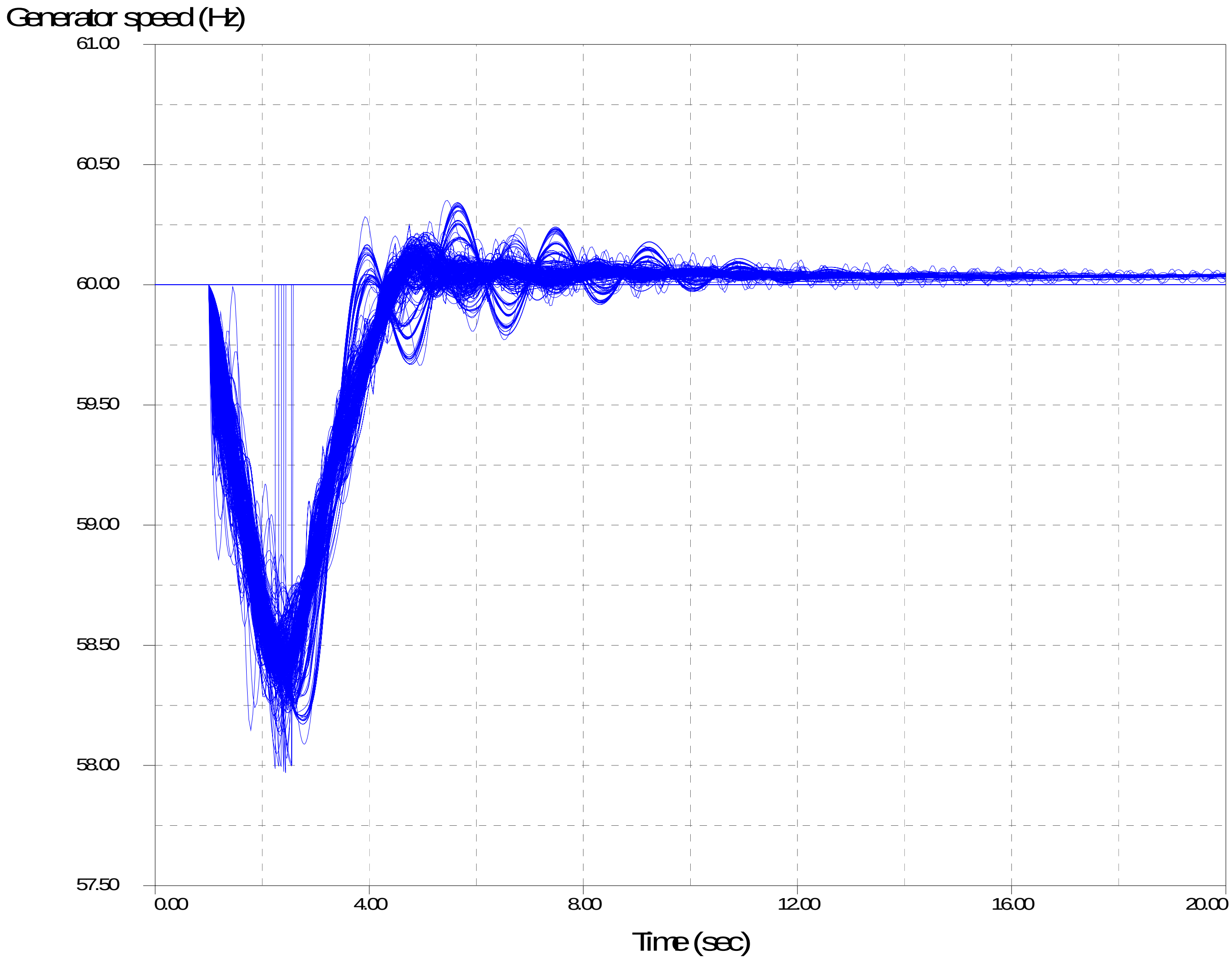

Figure 4-15: Generator Frequency for Scenario 2011_30%GS with 40 cycles delay

The simulation results indicated that the generator under-frequency protection disconnected seven generators (531461, 531462, 640016. 640026, 640401, 640418, 659134).

Table 4-15: Generators tripped by under-frequency requirement for 40-cycle delay

Generation Shed during 40-cycles delay scenario						
No.	**Area#**	**Area Name**	**Bus #**	**Bus Name**	**Gen ID**	**MW**
1	534	SUNC	531461	S4 GEN 1 13.2	4	48.00
2			531462	S4 GEN 1 13.2	5	48.00
3	640	NPPD	640016	KINGSLYG 13.8	1	33.00
4			640026	AINSWD1W 0.60	1	12.00
5			640401	W.POINTG 34.5	1	7.40
6			640418	ELKRDG1W 34.5	1	16.00
7			659134	SIDNEY 4 230.	1	20.00
					Total:	184.40

As a part of UFLS evaluation, V/Hz for all SPP generators for this scenario was studied. The objective of this was to identify generators for which V/Hz exceeds 1.18 pu for longer than two seconds cumulatively, or exceeds 1.1 pu for longer than 45 seconds cumulatively for simulated event of 30% generation scenario. The plots of generator V/Hz are depicted below. As shown in this figure no generator V/Hz exceeds 1.18 pu; however a number of generators V/Hz exceeded 1.1 pu.

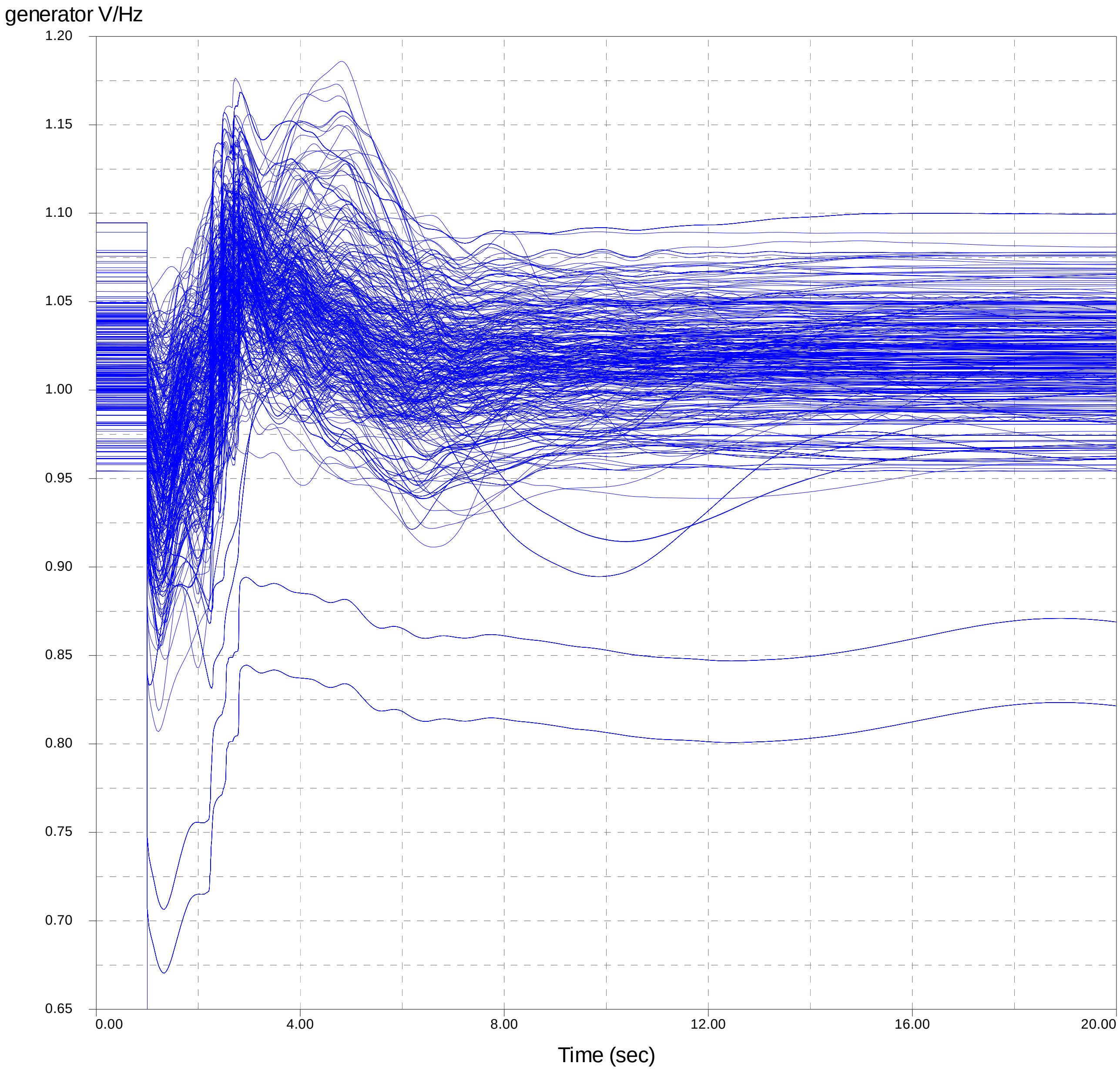

Figure 4-16: Generators V/Hz for 30%_GS with 40 Cycles Delay

The simulation results indicated that 49 generators measured V/Hz exceeds 1.1 pu for more than a second; however, the calculated cumulative times for generators' V/Hz are considerably less than 45 seconds.

It was noted as the system transients following the simulated event settles and system response reaches a steady state, the terminal voltage of five generators connected to bus number 533582 practically becomes 1.1 pu (in fact the terminal voltage becomes ~1.098 pu). Therefore, the V/Hz for these generators become close to the stipulated value of 1.1 pu at steady state.

Cursory comparison between generator frequency plots for 40 cycle delay versus 30 cycle delay indicates less generator oscillation for 40 cycle delay. This observation is believed to be mainly contributed to system-wide implementation of generator under-frequency protection, as five additional generators were disconnected under 40 cycles delay case.

5 Conclusions & Recommendations

In this study, the UFLS program of SPP was evaluated. As part of NERC/SPP compliance program requirements, SPP members compiled and submitted their load shedding relay data. SPP members have maintained and updated their UFLS relay data every five years (the last update was reported in 2006). The review of relay data shows that the relay settings, load shedding amount in each stage of load shedding, and time delays adhere to the NERC/SPP requirements. The simulated events also indicated that the UFLS program is reasonably coordinated with generation protection[10], and is reasonably immune to UFLS relay under-voltage inhibit setting of 85% and below. In order to study sensitivity of UFLS program to trip time setting, the effect of a universal relay pickup time setting for UFLS program was studied. The simulation results for 30% generation loss event with UFLS scheme relays' pickup time adjusted up to 40 cycles while all generators equipped with under-frequency protection indicated that the system remains reasonably secure following the operation of established UFLS program.[11] Additional generator protective concerns such as excessive magnetic flux (V/Hz) and generator under-frequency requirement were also investigated, and it was determined that generators V/Hz performance was within stipulated range.

The following outlines stipulate major findings that substantiate SPP's compliance to the UFLS program:

- Review of the SPP relay data reveals that SPP and its members closely adhere to a coordinated load shedding scheme. Additionally, the study indicates that there is no unusual protection requirement that necessitate special coordination with other NERC regions.

- Review of the SPP relay data and dynamic simulation of severe generation/load imbalance scenarios, showed SPP and its members closely adhere to a coordinated (amount and frequency set-points) load shedding scheme to arrest frequency decline. The coordinated UFLS program does not warrant minimization of load shedding; however, the study results do not appear to indicate that excessive load shedding has taken place with existing UFLS program. Regarding system restoration, the only comment that can be made is that the result did not show any loss of tie lines (within SPP) during frequency decline that could prolong restoration progress.

- The SPP's UFLS assessment using a time-domain simulation program is being conducted periodically (the last evaluation was performed five years ago in year 2006).

- The relay data and simulation results showed SPP members have a generally[12] consistent (amount, frequency set-points and relay and breaker operating time)

[10] Based on the generator under frequency relay data in database.
[11] Additional load was disconnected compared to 30% gen loss scenario.
[12] Even though there are instances that relay operating times are not consistent possibly due to relay types (e.g. electromechanical versus solid state) but this should not be interpreted as having an inconsistent program.

UFLS program.

- The SPP members have defined a protection relay data in MS Excel format. The SPP members have compiled necessary information for different relay types. This data has been used effectively in the present study. SPP members should maintain this data and update it annually.

- The result of time-domain simulations in this study proved that the SPP UFLS program is indeed effective in arresting frequency decline under conditions of severe mismatch between load and generation.

- As part of NERC compliance SPP should maintain and update the UFLS relay data annually.

- As part of NERC compliance SPP should conduct a study, similar to the one reported herein, every five years in order to provide evidence that its UFLS program is effective to cope with system changes.

Recommendations

Based on the findings of this study, the following recommendations are provided,

(a) Review of SPP relay settings indicated that these settings are satisfactory throughout the SPP system and adhere to NERC and SPP UFLS standards. However some members have relatively low percentage (≤ 20%) of UFLS armed loads. The areas LAFA, LEPA, SWPA, MIDW, INDN, NPPD and LES have UFLS armed load ratios that are substantially lower than 30%. As stipulated by SPP UFLS standard 7.3.1.3.a., members must be ready to shed 30% of their load by UFLS relays.

(b) It is recommended that SPP members investigate if any of their generating units have over-speed protections with settings around 61.5 Hz. This is the highest over frequency observed in the simulation of the server generation loss and 45% load shedding scenario. The observed duration for this frequency, 61.5 Hz, was substantially shorter than the maximum allowable duration of 10 seconds stipulated by over-frequency requirement curve.

This report is prepared by standard of care and based on the information supplied by SPP for and during the course of this study.

6 References

[1] NERC Reliability Standards for the Bulk Electric Systems of North America, February 7, 2006.

[2] Southwest Power Pool Criteria, October 2004.

[3] C. Concordia, L. Fink, G. Poullikkas, "Load Shedding on an Isolated System", IEEE Transaction on Power Systems, Vol. 10, No. 3, August 1995

[4] Mukesh Nagpal, Ali Moshref, et al, "Dynamic Simulations Optimize Application of an Under Frequency Load Shedding Scheme", Presented to the 24th Annual Western Protective relaying Conference, Spokane, WA, October, 1997

[5] D. W. Smaha, C. R. Rowland, and J. W. Pope, "Coordination of Load Conservation with Turbine-Generator Under frequency Protection," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-99, No. 3, pp. 1137–1150, May/June 1980.

[6] C. W. Taylor, F. R. Nassief, and R. L. Cresap, "Northwest Power Pool Transient Stability and Load Shedding Controls for Generation–Load Imbalances", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 7, pp. 3486–3495, July 1981.

[7] K. L. Hicks, "Hybrid Load Shedding is Frequency Based", IEEE Spectrum, pp. 52–56, February 1983.

7 Appendix A – NERC UFLS Standards

As of April 1st, 2005 the NERC Reliability Standards superseded the NERC Planning Standards. The following Reliability Standards (PRC-006 to PRC-009) apply to UFLS programs and have been extracted from the NERC document "Reliability Standards for the Bulk Electric Systems of North America" dated February 7, 2006 [1].

Standard PRC-006-0 — Development and Documentation of Regional UFLS Programs

Effective Date: April 1, 2005

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.

Standard PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements
Effective Date: April 1, 2005

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 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.

Standard PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs
Effective Date: April 1, 2005

A. Introduction

1. **Title: Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program**
2. **Number:** PRC-008-0
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 have a UFLS program
   - **4.2.** Distribution Provider required by its Regional Reliability Organization to have 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 have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).

C. Measures

M1. Each Transmission Owner's and Distribution Provider's UFLS equipment maintenance and testing program contains the elements specified in Reliability Standard PRC-008-0_R1.

M2. Each Transmission Owner and Distribution Provider shall have evidence that it provided the results of its UFLS equipment maintenance and testing program's implementation to its Regional Reliability Organization and NERC on request (within 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: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.2. Level 2: Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation was not provided.

E. Regional Differences

1. None identified.

Standard PRC-009-0 — UFLS Performance Following an Underfrequency Event

Effective Date: April 1, 2005

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.

8 Appendix B – SPP UFLS Standards

The following has been extracted from Section 7 of the October 2004 revision of the Southwest Power Pool Criteria document [2].

7.3 UNDER-FREQUENCY LOAD SHEDDING AND RESTORATION

7.3.1 Automatic Load Shedding

A major disturbance among the interconnected bulk electric system may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. The areas of separation are unpredictable. To provide load relief and minimize the probability of network collapse the following practices are established.

7.3.1.1 Operating Reserve

All SPP operating reserve shall be utilized before resorting to shedding firm load. During a period of declining frequency, there may be violent swings of both real and reactive power. For this reason, all generator governors and voltage regulators shall be kept in automatic service as much as practical.

7.3.1.2 Operating Principles

a. To realize the maximum benefit from a load shedding program the points at which the load is shed in a company area shall be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

b. The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining frequency. The only practical way to remove load from a member in an attempt to stabilize the frequency is to do so automatically by the use of under-frequency relays. Since a geographical area or the timing of a period of low frequency cannot be predicted, all of the designated under-frequency relays on a member system shall be in service at all times. Underfrequency relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

c. The accepted practice of the electric industry is to shed load in a minimum of three steps. Should the frequency continue to decline after these three steps of load shedding, additional action may be required to protect generating machinery from mechanical damage. The actions may include opening of tie-lines, removal of generating units from the bus, additional steps of load shedding, or "island" operation may be utilized automatically with enough load left on a machine or plant to keep it in operation. A member can elect to use any one or a combination of these actions. It is recommended that this operation be performed at 58.5 Hz. Whatever is done by any one member shall be coordinated with neighboring members. A map or chart which shows additional actions that will be taken below a frequency of 58.7Hz shall be furnished to SPP.

7.3.1.3 Implementation

a. Should the utilization of spinning reserve fail to stop a frequency decline, load shedding shall be initiated in steps as indicated below. The goal of the program is to prevent a cascading outage due to a frequency excursion and restore the system to a stable condition. Members must be ready to shed, in three steps, thirty (30) percent of a member's current load regardless of the starting load point (i.e. peak-load, shoulder-load, low-load). This requirement shall be achieved as follows: 1) A member may dynamically arm and disarm UFLS relays to achieve the required load shedding totals, indicated in the chart below, by utilizing a load following program. For the purposes of this section, the term 'dynamically' means that no operator intervention is required to arm or disarm a UFLS relay, or 2) A member that does not dynamically arm and disarm UFLS relays shall install, or have installed on its behalf, UFLS relays with a total capability of shedding a minimum of thirty (30) percent of the member's current load. The relays shall be set to shed the thirty (30) percent total in increments of current load per step, as indicated in the chart below. Once installed, these UFLS relays shall remain in service to trip loads except for periods of testing and maintenance.

Regardless of the technique utilized only the non-intentional delays including operating times of relays and breakers, plus any intentional delay as allowed in Criteria 7.3, shall delay the interruption of pre-event load for all events at the time of each event.

Step	Frequency (hz)	Minimum Load Relief (%)
1	59.3	10
2	59.0	10
3	58.7	10

b. The relays used to accomplish load shedding shall be high speed with no external intentional time delay devices employed. An exception to this policy would be on circuits serving considerable motor load (such as oil field or irrigation pumping load) which would cause the under-frequency relays to incorrectly operate when the source voltage is removed momentarily due to a transmission line fault.

c. Some members may elect to shed more than 10% of the system load on any step, particularly, if they have an adverse ratio of load responsibility to generating capability. This situation is not general and shall be considered on the merits of specific cases.

d. The tripping of any generating unit by under-frequency relays or any other protective device during low frequency conditions shall be so coordinated that these units will not be tripped before the three steps of load shedding have been utilized. Should this not be practical due to the operating characteristics of certain units, then, these members shall protect the interconnected systems by shedding a block of load equal to the capability of the generating unit that will be tripped and at the frequency which will remove the unit from service. If the unit is jointly owned, each of the joint owners shall shed a block of load equal to their share of the unit.

e. The coordination among members becomes critical when actions beyond Step 3 are utilized; particularly, on those members which have established extra high voltage (EHV) terminals as part of their transmission system and/or with generators connected directly to the EHV system. Careful consideration shall be given when opening only one end of an EHV line section which is energized; the open-ended voltage could rise to damaging levels and reactive flow towards the closed-end could have intolerable effects. Further, if generation is connected to the affected portion of the EHV network, that generating capability would be removed from an area where it is sorely needed. Consideration shall be given to the coordination of under frequency relaying of the EHV transmission to maintain generating units on line and if necessary, carry portions of a neighboring system load to do so. System operators shall be alert to the effects of unloading the EHV network and be prepared to remove portions of the network should the voltage rise to intolerable levels.

7.3.1.4 Required Location And Model Data Reporting For Under-frequency Load Shedding Equipment

The number, type and location of Under-frequency Load Shedding (UFLS) equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in databases by the SPP staff for a period of at least three (3) years. These modeling databases shall be monitored as necessary by the SPP System Protection and Control Working Group (SPCWG). The Model Development Working Group, Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities is installed at critical locations throughout the system as determined in power flow and dynamic stability studies. The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, location, breaker, trip frequencies, amount of load shed by trip frequency, relay and breaker operating times, and any intentional delay of breaker clearing. Also required will be any related generation protection, tie tripping schemes, islanding schemes, or any other schemes that are part of or impact the UFLS programs.

7.3.1.5 Requirements for Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means (i.e. self-testing microprocessor relays) to periodically check the functionality and

availability of the UFLS equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility
owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.3.1.6 Periodic Review of Under-frequency Load Shedding Equipment

SPP members shall maintain a list of substations where UFLS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the UFLS equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.3.1.4. The SPCWG will update, if necessary, this UFLS Criteria every three (3) years.

7.3.1.7 Requests for Under-frequency Load Shedding Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners should provide the requested data within five (5) business days with a copy of the requested information forwarded to the SPP. However, it is recognized that significant disturbances may result in a large amount of equipment operations at multiple locations and that some equipment operations must be manually retrieved from the UFLS equipment's locations. These factors may make it impractical to retrieve and properly prepare the records and documentation within five (5) business days. In these cases, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.3.1.8 Restoration

After the frequency has stabilized the following procedure shall be followed.

a. In the event the frequency stabilized below 60 Hz, system operators shall coordinate operations to utilize all available generating capacity to the maximum extent possible in order to restore the frequency to 60 Hz. Deficient systems shall continue to shed load until the frequency can be restored to normal.

b. At 60 Hz the isolated areas shall be synchronized with the remainder of the interconnected systems. Synchronization between individual members shall be performed only upon direct orders of the system operators of both companies involved.

c. System operators shall coordinate load restoration as generating capability, voltage levels and tie-line loadings allow.

d. Any shed load shall be restored only upon direct orders of the system operator. Extreme care shall be exercised as to the rate at which load is restored to the system in order that limits of generation and transmission line loading are not exceeded. Insofar as possible, supervisory control shall be used to restore load; otherwise, manual restoration is preferable to insure positive control by the system operators.

e. It is recommended that a restoration plan be furnished by each company for use by its system operators for implementation of a coordinated and successful recovery.

7.3.2 Requirements of a Regional Under-frequency Load Shedding Program

The SPP shall develop, coordinate, and document a Regional UFLS program.

7.3.2.1 SPP's Coordination of Under-frequency Load Shedding Program

This program shall coordinate UFLS programs within the sub-regions, Region, and where appropriate, among Regions. It shall also coordinate the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration. For an effective plan, SPP shall coordinate programs including generation protection and control, under-voltage load shedding, Regional load restoration, and transmission protection and control. Details to be included shall include those specified in 7.3.1.4. SPP shall periodically conduct and document a technical assessment of the effectiveness of the design and implementation of its UFLS program. The first technical assessment of the program shall be completed by SPP no later than June 1, 2001. These assessments shall be completed at least every five years thereafter or as required by significant changes in system conditions. The documented results of such assessments shall be provided to NERC on request.

7.3.2.2 Coordination of Under-frequency Load Shedding Programs And Analyses With SPP

The facility owners and operators of an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements including automatically shedding load in the amounts and at the locations, frequencies, rates and times consistent with those Regional requirements. When an under-frequency event occurs which is below the initializing set points of their UFLS programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.3.1.7.

7.3.3 Manual Load Shedding

A situation can arise when a control area must reduce load even though the frequency is normal. Since an automatic load shedding program will be of no avail in this case, manual load shedding procedures shall be utilized. One of the basic principles of interconnected operation is that a control area will match the area generation to area load at 60 Hz at all times. Should a generation deficiency develop for any reason, arrangements shall be made with adjacent control areas to cover the deficiency; but failing this, the affected control area shall reduce the area load until the available generation is sufficient to match it. In some cases a generation deficiency can be foreseen and will develop gradually; whereas, in other cases the deficiency will develop immediately with no forewarning. A gradually developing deficiency can probably be offset by using conservation procedures; whereas, an immediate deficiency will probably require customer service interruption. The importance of a load reduction plan cannot be overemphasized. A plan is offered here which can be modified to fit individual cases.

7.3.3.1 Conservation

a. Interruption of service to interruptible customers. Utilize to the extent that the situation requires.

b. Reduction of load in company facilities.

c. Reduction of distribution voltage level. Utilize to the extent possible and as the situation requires.

d. Load reduction by request to company employees and general public. The company employees and the general public shall be notified through news media to curtail the use of electricity.

e. Load reduction by request to bulk power users. Concurrent with voltage reduction and asking employees and the general public to reduce load, bulk power users (municipals and cooperatives) will be asked to reduce load in their areas using the same methods.

f. Load reduction by large use customers. Large use commercial and industrial customers will be requested to curtail electric power usage where such curtailment will not seriously disrupt customers' operations.

7.3.3.2 Service Interruption

Manual load interruption shall be implemented by a pre-determined plan, an example of which follows.

a. Each company operating subdivision shall select distribution circuits in approximately 5% increments in the order of their priority that will be taken out of service. The 5% increments will be labeled "A", "B", "C", "D", "E", and "F". The interruption and the restoration of these circuits will be under the control of the system operator. When the system operator determines that load must be reduced, he shall direct the subdivision operators to open all "A" circuits. This will reduce the system load 5%. If further load reduction is necessary, the system operator shall direct all "B" circuits to be opened which will result in an additional 5% reduction. This shall continue through "C", "D", "E", and "F" until the generation deficiency is eliminated.

b. The objective of this plan is to have no circuits open more than two hours. If the duration of the system emergency exists in excess of two hours and only the "A" circuits have been opened, then at the end of two hours the "B" circuits shall be opened and the "A" circuits reclosed. If a 10% reduction is necessary, "C" and "D" circuits shall be opened and "A" and "B" reclosed, after "A" and "B" have been open for two hours. Obviously, no circuits shall be open longer than is absolutely necessary. The "E" and "F" circuits shall be opened to avoid opening "A" and "B" circuits twice in one day.

c. When a generation deficiency develops, or begins to develop, the system operator shall alert all involved operating personnel to the effect that certain circuits may have to be interrupted. This action will reduce the time required to execute circuit interruption orders of the system operator. Some control areas in SPP have extensive supervisory control systems while others have little, if any, supervisory control. Obviously, any implementation plan shall make best use of available equipment.