NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

December 19, 2007

VIA ELECTRONIC FILING

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

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

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations seeking approval for interpretations of requirements in four Commission-approved NERC Reliability Standards that are contained in Exhibits A-1, B-1, and C-1 to this petition:

- BAL-001-0 — Real Power Balancing Control Performance, Requirement R1
- BAL-003-0 — Frequency Response and Bias, Requirement R3
- BAL-005-0 — Automatic Generation Control, Requirement R17, and
- VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules, Requirements R1 and R2.

The formal interpretations have been approved by the NERC Board of Trustees. NERC requests these interpretations be made effective immediately after approval by the Commission.

NERC's petition consists the following:

- This transmittal letter;
- A table of contents for the entire petition;
- A narrative description explaining how the formal interpretations meet the reliability goal of the standards involved;
- Formal interpretations submitted for approval (Exhibits A-1, B-1, and C-1);
- Affected Reliability Standards that include the appended interpretations (Exhibits A-2, B-2, and C-2); and
- The complete development record of the formal interpretations (Exhibits A-3, B-3, and C-3).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Rebecca J. Michael

Rebecca J. Michael

Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**) Docket No. RM06-16-000**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF FORMAL INTERPRETATIONS TO RELIABILITY STANDARDS

Rick Sergel
President and Chief Executive Officer
David N. Cook
Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

Rebecca J. Michael
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
rebecca.michael@nerc.net

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I. INTRODUCTION

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

– BAL-001-0 — Real Power Balancing Control Performance, Requirement R1

– BAL-003-0 — Frequency Response and Bias, Requirement R3

– BAL-005-0 — Automatic Generation Control, Requirement R17, and

– VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules, Requirements R1 and R2.

This petition is the first request by NERC for Commission approval of these formal interpretations to requirements of existing Commission-approved NERC Reliability Standards. No modifications to the language contained in these specific requirements are being proposed. However, NERC has included for the Commission's information the approved Reliability Standards to which the proposed interpretations are appended.

The NERC Board of Trustees approved the formal interpretation to BAL-005-0 — Automatic Generation Control, Requirement R17 on May 2, 2007; VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules, Requirements R1 and R2 on August 1, 2007; and, BAL-001-0 — Real Power Balancing Control Performance,

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

Requirement R1 and BAL-003-0 — Frequency Response and Bias, Requirement R3 on October 23, 2007. NERC requests that the Commission approve these formal interpretations and make them effective immediately after approval in accordance with the Commission's procedures. Exhibits A-1, B-1, and C-1 to this filing set forth the formal interpretations. Exhibits A-2, B-2, and C-2 contain the affected Reliability Standards containing the appended interpretations. Exhibits A-3, B-3, and C-3 contain the complete development records of the formal interpretations to the Reliability Standard requirements.

NERC also is filing these formal interpretations with governmental authorities in Canadian provinces and with the National Energy Board of Canada.

II. NOTICES AND COMMUNICATIONS

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

Rick Sergel
President and Chief Executive Officer
David N. Cook*
Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

Rebecca J. Michael*
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
rebecca.michael@nerc.net

*Persons to be included on the Commission's service list are indicated with an asterisk.

III. BACKGROUND

a. Regulatory Framework

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

b. Basis for Approval of Proposed Reliability Standard

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

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

[3] Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005 (to be codified at 16 U.S.C. § 824o).
[4] Section 215(d)(2) of the FPA, to be codified at 16 U.S.C. § 824o(d)(2) (2000).

When evaluating proposed reliability standards, the Commission is expected to give "due weight" to the technical expertise of the ERO. Order No. 672 provides guidance on the factors the Commission will consider when determining whether proposed reliability standards meet the statutory criteria.[5] While these formal interpretations do not represent new or modified reliability standard requirements, they do provide formal instruction with regard to the intent and in some cases application of the requirements that will guide compliance to them. In this regard, NERC requests approval from the Commission on these interpretations.

c. Reliability Standards Development Procedure

NERC develops reliability standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Reliability Standards Development Procedure*, which is incorporated into the Rules of Procedure as Appendix 3A. In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing reliability standards and thus satisfies certain of the criteria for approving reliability standards.[6]

The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders and a vote of stakeholders and the NERC Board of Trustees is required to approve a reliability standard for submission to the Commission.

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[5] *See* Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, FERC Stats. & Regs., ¶ 31,204 at PP 320-36 ("Order No. 672"), order on reh'g, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").
[6] Order No. 672 at PP 268, 270.

Additionally, all persons who are directly or materially affected by the reliability of the North American bulk power system are permitted to request an interpretation of the reliability standard, as discussed in NERC's *Reliability Standards Development Procedure.* When requested, NERC will assemble a team with the relevant expertise to address the interpretation request and, within 45 days, present a formal interpretation for industry ballot. If approved by the ballot pool and the NERC Board of Trustees, the interpretation is appended to the reliability standard and filed for approval by the Commission and regulatory authorities in Canada to be made effective when approved. When the affected reliability standard is next revised using the reliability standards development process, the interpretation will then be incorporated into the reliability standard.

The formal interpretations set out in Exhibits A-1, B-1, and C-1 have been developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure*, and they have been approved by the NERC Board of Trustees as outlined in the Introduction section above.

IV. BAL-001-0 — Real Power Balancing Control Performance, Requirement R1 and BAL-003-0 — Frequency Response and Bias, Requirement R3

The Commission approved Reliability Standards BAL-001-0 and BAL-003-0 in Order No. 693.[7] In Section IV(a), NERC explains the need for and development of the formal interpretations of BAL-001-0 — Real Power Balancing Control Performance, Requirement R1 and BAL-003-0 — Frequency Response and Bias, Requirement R3. In addition, NERC demonstrates that the formal interpretation is consistent with the stated

[7] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 at PP 308, 375 and Appendix A (2007) (Order No. 693), *order on reh'g*, *Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

reliability goal of the Commission-approved Reliability Standards and the requirements thereunder. Set forth immediately below in Section IV(b) are the stakeholder ballot results and an explanation of how stakeholder comments were considered and addressed by the standard drafting team assembled to provide the interpretation.

The complete development record for the formal interpretation is set forth in Exhibit A-3. Exhibit A-3 includes the request for interpretation, the response to the request for interpretation, the ballot pool and the final ballot results by registered ballot body members, stakeholder comments received during the balloting and how those comments were considered.

a. Justification for Approval of Formal Interpretation

The stated purpose of BAL-001-0 — Real Power Balancing Control Performance (the "control performance standard" or "CPS") is "to maintain interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time." Requirement R1 of this Reliability Standard provides the definition of area control error ("ACE") and the limits established for control performance standard 1:

> **Requirement R1.** Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

The stated purpose of BAL-003-0 — Frequency Response and Bias is to "provide a consistent method for calculating the Frequency Bias component of ACE."

Requirement R3 of this Reliability Standard addresses the use of tie-line frequency bias as the normal mode of automatic generation control used by balancing authorities:

> **Requirement R3.** Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

On June 1, 2007, the Western Electricity Coordinating Council ("WECC") requested that NERC provide a formal interpretation of Requirements R1 and R3 of the BAL-001-0 and BAL-003-0 Reliability Standards, respectively. Specifically, WECC asked if the use of the WECC's existing Automatic Time Error Correction ("WATEC") procedure, which is currently proposed to be a regional reliability standard, violates Requirement R1 of BAL-001-0 or Requirement R3 of BAL-003-0.

WECC's proposed regional reliability standard is based on the existing WATEC procedure[8] that makes the WATEC process mandatory for balancing authorities in the Western Interconnection. (WECC submitted a regional reliability standard regarding WATEC for NERC review in August 2007 and the proposed regional reliability standard is being processed for approval through the NERC *Reliability Standards Development Procedure* in accordance with NERC's Rules of Procedure.) During the development of the proposed regional reliability standard, however, members of WECC expressed some concern that compliance with the existing WATEC process would result in non-compliance with certain of the NERC's Reliability Standards and would thus create a conflict.

According to WECC, if WECC's current WATEC approach is determined by NERC and the Commission to be appropriate, then interim clarification in the form of a formal interpretation would allow WECC users, owners, and operators to continue to

[8] http://www.wecc.biz/documents/library/procedures/Time_Error_Procedure_10-04-02.pdf

utilize WATEC as regional criteria until a WECC regional reliability standard is formally approved by the Commission. The first question posed by WECC is: "does the use of the [WATEC] procedure violate Requirement R1 of BAL-001-0?" As explained below, the use of WATEC for control does not result in a violation of BAL-001-0 Requirement R1, provided that (i) WECC's balancing authorities use the raw and unadjusted ACE for control performance reporting purposes, and (ii) the raw unadjusted ACE complies with Requirement R1.

WECC proposed a second question in its request for interpretation: "does the use of the [WATEC] procedure violate Requirement R3 of BAL-003-0"? Also, as explained below, the use of the WATEC procedure does not violate Requirement R3 of BAL-003-0, provided that (i) a balancing authority uses the tie-line frequency bias mode as the underlying control mode, and (ii) Control Performance Standard ("CPS1") (per BAL-001-0 Requirement R1) is measured and reported on the associated ACE equation.

In order to provide the context for the formal interpretations, it is necessary to explain the differences in the ACE calculation in the NERC Reliability Standard and the existing WATEC procedures. NERC's BAL-001-0 Reliability Standard includes the following description for ACE:

$$ACE = (NI_A - NI_S) - 10B\ (F_A - F_S) - I_{ME}$$

where

- NI_A is the algebraic sum of actual flows on all tie-lines.
- NI_S is the algebraic sum of scheduled flows on all tie-lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the balancing authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. FS is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie-line flows

(NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

WATEC utilizes this basic ACE equation modified with an automatic time error correction term and with T_{0b} added:

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - T_{0b} + I_{ME} + \{\text{WECC Time Error Correction Term}\}$$[9]

The automatic time error correction component is based on a balancing authority's accumulated primary inadvertent interchange. In addition, WECC includes another inadvertent interchange offset term in the ACE equation, T_{0b}, to bilaterally correct inadvertent interchange accumulations. In part 1.a.3. of the WECC procedure for time error control, WECC clearly states that the time error bias term shall not be used in ACE when determining CPS compliance but shall be used for control only. Likewise, the WECC description of the ACE calculation[10] also states that this term is not to be included for NERC performance reporting. This direction is important relative to the formal interpretation.

Pursuant to the *Reliability Standards Development Procedure*, NERC selected the Resources Subcommittee of the NERC Operating Committee as its subject matter expert to consider the two questions and develop the interpretation responses.

Does the use of the WATEC procedure violate Requirement R1 of BAL-001-0?

The use of WATEC does not violate Requirement R1 of BAL-001-0. Control performance is measured using the ACE equation and is determined to be satisfactory if a balancing authority remains within established limits as defined in Requirement R1. The

[9] For the purposes of this discussion, the WECC time error correction term does not need to be detailed.
[10] http://www.wecc.biz/documents/library/procedures/ACE_Description_Final_4-21-06.pdf

WATEC procedure requires balancing authorities to maintain a raw ACE that is not layered with other control objectives (such as automatic time error correction or manual inadvertent interchange payback) for control performance reporting to NERC. WECC's balancing authorities control their balancing authority areas using the WATEC-adjusted ACE.

The use of WATEC for control does not result in a violation of BAL-001-0 Requirement R1, provided that (i) WECC's balancing authorities use the raw and unadjusted ACE for control performance reporting purposes and (ii) provided the raw unadjusted ACE complies with Requirement R1. However, compliance with the WATEC procedure does not necessarily result in compliance with NERC CPS1 as required by Requirement R1. By using the raw, unadjusted ACE values, NERC is able to measure WECC's balancing authorities' performance on a consistent basis with other balancing authorities across North America. In this regard, the formal interpretation supports the objective for BAL-001-0: to maintain interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.

Does the use of the WATEC procedure violate Requirement R3 of BAL-003-0?

The use of the WATEC procedure does not violate Requirement R3 of BAL-003-0. Requirement R3 requires each balancing authority to operate its AGC in the tie-line frequency bias mode. Tie-line frequency bias is one of the three foundational control modes available in a balancing authority's energy management system. The other two are flat-tie and flat-frequency modes.

Many balancing authorities layer other control objectives on their basic control mode, such as automatic inadvertent payback, control performance standard optimization, time control (in single balancing area interconnections), for example. Provided that a balancing authority uses the tie-line frequency bias mode as the underlying control mode and CPS1 (per BAL-001-0 Requirement R1) is measured and reported on the associated ACE equation, there is no violation of BAL-003-0 Requirement R3. This formal interpretation of R3 of BAL-003-0 reinforces the expectation that tie-line frequency control is the preferred control mode for balancing authorities in North America and thereby supports the purpose of the Reliability Standard: to provide a consistent method for calculating the frequency bias component of the ACE equation.

In addition, the Commission has noted in paragraphs 377, 385, and 386 of Order No. 693 that WECC's automatic time error correction procedure as discussed in this interpretation is more effective in minimizing both time error corrections and inadvertent interchange than the NERC continent-wide reliability standard. This interpretation comports with the Commission's determinations in Order No. 693.

b. Summary of the Reliability Standard Development Proceedings

On June 1, 2007, WECC requested that NERC provide formal interpretations of Requirements R1 and R3 of the BAL-001-0 and BAL-003-0 Reliability Standards, respectively. In accordance with its *Reliability Standard Development Procedure*, NERC posted its response to the request for interpretation for a 30-day pre-ballot period that took place from July 9, 2007 – August 7, 2007. NERC conducted an initial ballot from August 7, 2007 – August 16, 2007, but a negative vote was received with associated comments. This triggered the need to conduct a recirculation ballot after the interpretation team responded to the comments. Accordingly, a recirculation ballot was conducted from August 23, 2007 – September 1, 2007. The formal interpretations were approved by the ballot pool with a weighted segment average of 97.2 %, with 96.3 % of the ballot pool voting.

Four sets of comments were received during the ballot process, with only one tied to a negative ballot. Supporting comments from Duke Energy and the California Energy Commission highlighted how the distinctions in the interpretation do not adversely impact any party in other interconnections and allows the interconnections that want to use automatic time error correction the ability to do so. This procedure requires that raw ACE used for reporting of CPS compliance per the BAL-001-0 Reliability Standard and disturbance control standard performance per BAL-002-0 does not include the WATEC modified time error correction term. Duke Energy suggested that balancing authorities in WECC should provide certain assurances to WECC that the raw ACE is being calculated in accordance with the NERC Reliability Standard BAL-001-0 for compliance purposes. NERC agrees with this comment but offers that the validation of such important information should occur in the domain of normal compliance audits, not in standards development.

NERC did receive one comment associated with a negative vote. Xcel Energy stated that the interpretation appears to creates a disconnect between the way one Region implements the ACE calculation compared to the NERC ACE, under which all compliance will be determined. NERC responded that many balancing authorities are permitted to, and employ, a modified control ACE for a variety of reasons. As set forth above, provided the balancing authorities calculate and report their performance using raw ACE, their conformance to the requirements is measured in a comparable manner, which is the overall goal.

Energy Mark, Inc. abstained during the vote but commented that the proposed WECC procedure does not have a compliance measure established today. The purpose of this interpretation is not to discuss the merits of the proposed WECC procedure nor the compliance expectations for it. Generally, from a procedural standpoint, an interpretation of a NERC Reliability Standard is not the mechanism to add or modify elements of the Reliability Standard.

V. BAL-005-0 — Automatic Generation Control, Requirement R17

The Commission approved Reliability Standard BAL-005-0 in Order No. 693.[11] In Section V(a), NERC explains the need for and development of the formal interpretation of BAL-005-0 — Automatic Generation Control, Requirement R17. In addition, NERC demonstrates that the formal interpretation is consistent with the stated reliability goal of the Commission-approved Reliability Standards and the requirements thereunder. Set forth immediately below in Section V(b) are the stakeholder ballot results and how stakeholder comments were considered and addressed by the team assembled to provide the interpretation.

The complete development record for the formal interpretation is set forth in Exhibit B-3. Exhibit B-3 includes the request for interpretation, the response to the request for interpretation, the ballot pool and the final ballot results by registered ballot body members, stakeholder comments received during the balloting and how those comments were considered.

[11] *See* Order No. 693 at P 396 and Appendix A.

a. Justification for Approval of Formal Interpretation

The stated purpose of BAL-005-0 — Automatic Generation Control, in relevant part, is to establish requirements for balancing AGC necessary to calculate ACE. Requirement R17 of this Reliability Standard states:

> **Requirement R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, Mvar, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

On December 21, 2006, NERC received a request to provide a formal interpretation of Requirement R17. Specifically, the requester asked the following:

> "We are currently interpreting this as saying that the only devices that need to be calibrated are the time error and frequency devices (first sentence of [Requirement] R17) and that the list of device accuracy in the second sentence of [Requirement] R17 is simply the design accuracy of the devices listed and that those devices do not need to be calibrated on an annual basis (except the digital frequency transducer which is covered as a "frequency device" in the first sentence). Can you tell us if this is a correct interpretation?"

In accordance with the *Reliability Standards Development Procedure,* NERC selected the Resources Subcommittee of the NERC Operating Committee as its subject matter expert to consider the question and develop the interpretation response. On January 26, 2007, the Resources Subcommittee provided its interpretation as requested by NERC:

> "The Resources Subcommittee Frequency Task Force reviewed Policy 1, the predecessor to BAL-005-0, and exchanged correspondence with a member of the Version 0 Standards Drafting Team.[12] The Frequency Task Force determined <u>the intent of BAL-005-0, Requirement 17 is to annually check and calibrate [</u>an entity's<u>] control room time error and frequency devices against a common reference. No devices outside of the operations control room are addressed by this requirement</u>.
>
> The first sentence in [Requirement] R17 was taken from Policy 1 and related specifically to time error and frequency devices. The table was extracted from a guide in Policy 1, Appendix 1H as <u>recommended accuracy</u> values for all monitoring equipment.
>
> It should be noted that solid state equipment does not always allow output adjustment. In these cases, calibration resulting in readings outside of tolerances will require replacement."

Thus, the formal interpretation is that BAL-005-0, Requirement 17 requires only that only those devices in the operations control room must be annually checked and calibrated and that this reliability standard does not apply to devices outside the operations control room. This formal interpretation is consistent with the reliability objective of Requirement R17 of BAL-005-0 and with the overall goal of the Reliability Standard itself. The interpretation properly acknowledges that Requirement R17 expressly pertains to time error and frequency devices and identifies the balancing authority as the applicable entity. The devices pertaining to time error and frequency under the control of the balancing authority that feed into AGC necessary for area control error calculation are those located in the control rooms. In the first instance, other inputs to the ACE equation are not captured in the first sentence of Requirement R17, namely tie-line flows for calculation of net actual interchange. The interpretation cannot expand

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[12] The Version 0 Standards Drafting Team converted the former NERC Operating Policies and Planning Standards into the current format of the standards utilized today. Version 0 was chosen to reflect the team's activities of translating the policies and standards without performing quality improvements to the requirements. As such, the Version 0 team converted Operating Policy 1 that addressed automatic generation control elements to become BAL-005-0.

or change the requirement in a NERC Reliability Standard. By allowing the inclusion of other metering devices in the interpretation of Requirement R17, the scope of the requirement as stated and as approved by the Commission is dramatically expanded. The use of an interpretation for this purpose does not support the intent of an interpretation process as included in the *Reliability Standards Development Procedure*. Modifications to the Reliability Standard would more appropriately be considered when NERC addresses BAL-005-0 Reliability Standard as part of Project 2007-05 of its Reliability Standards Development Plan: 2008-2010, a project currently in progress. This plan was submitted to the Commission for information purposes on October 5, 2007.

In the second instance, the balancing authority is already required to perform tie-line MWh checks hourly through Requirement R13 of BAL-005-0. If errors are found, the balancing authority shall then adjust the metering error component of its ACE equation to compensate until such time the equipment is re-calibrated or replaced. Therefore, Requirement R13 addresses the accuracy of tie-line values in the calculation of ACE. Coupled with the requirement to calibrate frequency and time error devices in Requirement R17, the major inputs to the ACE equation are addressed.

Furthermore, the balancing authority may or may not be the entity that owns the physical equipment in the field that is used to telemeter input values to the balancing authority for the purposes of calculating ACE. The requirements for calibrating the field equipment is the responsibility of the transmission and generator owner and is contained within Reliability Standard PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing.

b. Summary of the Reliability Standard Development Proceedings

On December 21, 2006, NERC received a request for formal interpretation of Requirement 17 of the BAL-005-0 Reliability Standard. Pursuant to its *Reliability Standards Development Procedure*, NERC selected the Resources Subcommittee of the NERC Operating Committee to prepare the interpretation. On January 26, 2007, the Resources Subcommittee provided the formal interpretation that directs that only time error and frequency devices that are located in the control center are to be included in this requirement.

NERC published the formal interpretation for a 30-day pre-ballot review that started on February 15, 2007 and an initial ballot was conducted from March 19, 2007 – March 30, 2007. The interpretation was approved by a weighted average of 97.1 %, with 84.2 % of the ballot pool voting. However, three “no” votes were received with comments, triggering a need for a recirculation ballot after responding to the comments.

One commenter from the Public Utility District No. 2 of Grant County expressed concern about the use of the formal interpretation process as an indicator of a standard in need of modification and cautioned on the potential for abuse by circumventing the standard development process. Commenters from Westar Energy and Energy Mark, Inc., which voted for and against the interpretation, respectively, stated that the interpretation should refer to the check and calibration of all inputs to the area control error equation, whether or not they are contained in the control room. Energy Mark, Inc. argues that the interpretation should also be expanded to include the check and calibration of the intervening equipment used to transmit the tie-flow information to the control center. This would include the checking of turns-ratios and scaling factors included in the software in addition to the sensing equipment itself. As stated earlier, the Resources Subcommittee disagreed with this interpretation because it would expand the scope of the requirement that expressly states 'time error and frequency devices.' NERC has determined to include this issue in the scope of Project 2007-05 in its work plan.

NERC conducted the recirculation ballot on the formal interpretation from April 17, 2007 – April 26, 2007 and the interpretation passed with a weighted segment approval of 96.7 % with 91.7 % of the registered ballot pool participants casting a vote, exceeding the quorum requirement of 75 %.

VI. VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules, Requirements R1 and R2

The Commission-approved Reliability Standard VAR-002-1 in Order No. 693.[13] In Section VI(a), NERC explains the need for and development of the formal interpretations of VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules, Requirements R1 and R2. In addition, NERC demonstrates that the formal interpretations are consistent with the stated reliability goal of the Commission-approved Reliability Standard and the requirements thereunder. Set forth immediately below in Section VI(b) are the stakeholder ballot results and how stakeholder comments were considered and addressed by the team assembled to provide the interpretations.

The complete development record for the formal interpretations is set forth in Exhibit C-3. Exhibit C-3 includes the request for interpretations, the response to the request for interpretations, the ballot pool and the final ballot results by registered ballot body members, stakeholder comments received during the balloting and how those comments were considered.

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[13] *See* Order No. 693 at P 1884 and Appendix A.

a. Justification for Approval of Formal Interpretation

The stated purpose of VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules is to ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable facility ratings to protect equipment and the reliable operation of the interconnection. Requirements R1 and R2 of this standard state:

> **Requirement R1.** The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.
>
> **Requirement R2.** Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[14]) as directed by the Transmission Operator.

On January 24, 2007, NERC received a request to provide a formal interpretation of Requirements R1 and R2. Specifically, the requester asked the following questions:

> "First, does AVR (automatic voltage regulator) operation in the constant PF (power factor) or constant Mvar modes comply with [Requirement] R1?"
>
> "Second, does Requirement R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant pf or constant Mvar modes rather than the constant voltage mode?

In accordance with its *Reliability Standards Development Procedure*, NERC selected the Phase III/IV Planning Standards Drafting Team as its subject matter expert to consider the questions and develop the formal interpretations. This standard drafting team originally drafted the VAR-002-1 Reliability Standard that was approved by the

[14] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

NERC Board of Trustees in 2006 and was approved by the Commission in Order No. 693. On March 5, 2007, the team provided its interpretations as requested by NERC.

In response to the first question, “does AVR operation in the constant PF or constant Mvar modes comply with Requirement R1?” the following interpretation was provided:

> “No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.”

In response to the second question, “does [Requirement] R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant PF or constant Mvar modes rather than the constant voltage mode?” the following interpretation was provided:

> “Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.”

The team also supported its interpretation by including the following discussion in its formal response:

> “Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.
>
> Requirement R1 clearly states controlling voltage. This can only be accomplished by using the automatic voltage control mode. Using the Power Factor (PF) or constant Mvar control is not a true method to control voltage even though they may have some effect on voltage. This is the baseline mode of operation that is clearly conditioned by “unless the Generator Operator has notified the Transmission Operator.” The following Requirement R2 introduces the possibility of an exemption to this baseline mode of operation discussed below.

The above interpretation is further reinforced by reviewing the origin of the requirement. The current Requirement R1 is an evolution of the words in the associated source document, namely NERC Planning Standards Compliance Template for III.C.M1, "Operation of all synchronous generators in the automatic voltage control mode."

As stated in the original III.C.S1 Standard[15]:

> "All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved otherwise by the transmission system operator."

Requirement R2 of Standard VAR-002-1 goes on to state that "Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator." The purpose of this requirement is to give the Transmission Operator the ability to direct the Generator Operator to use another mode of operation. This ability may be necessary based on the Transmission Operator's system studies and/or knowledge of system conditions. This ability also gives the Transmission Operator the latitude to work with the Generator Operator who has a generating unit that lacks the physical equipment to be able to run in the automatic voltage control mode or has contractual requirements to operate in a certain manner.

Both Requirements R1 and R2 in VAR-002-1 were worded such that they coordinate with Requirement R4 in VAR-001-1:

> "Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage)."

[15] The NERC Planning Standards and NERC Operating Policies were the precursor to the comprehensive set of reliability standards that were approved by the NERC Board of Trustees in April 2005, known as Version 0. Until the Version 0 standards were approved, these operating policies and planning standards served as the core reliability guidance in the voluntary era of compliance that pre-dated the Energy Policy Act of 2005.

> Again this Requirement R4 reflects that the baseline mode of operation is to use the automatic voltage control mode with the option for the Transmission Operator to specify other modes of operation as dictated by system studies and needs to maintain system reliability."

NERC believes the formal interpretation and supporting discussion clearly state that the voltage control mode is the preferred method of operating the AVR unless the generator operator is expressly exempted by the transmission operator from operating in this mode. Further, the interpretation reinforces that the transmission operator is responsible to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable facility ratings to protect equipment and the reliable operation of the interconnection, which includes the provision of voltage and reactive support from generators. Thus, these interpretations directly support the intent of the requirements and the goal of the VAR-002-1 standard.

b. Summary of the Reliability Standard Development Proceedings

On January 24, 2007, NERC received a request for formal interpretation of Requirements R1 and R2 of the VAR-002-1 Reliability Standard. NERC selected members of the Phase III/IV standard drafting team that authored the Reliability Standard to prepare the interpretation. On March 5, 2007, the team provided the formal interpretations discussed in the previous section.

NERC published the formal interpretations for a 30-day pre-ballot review that started on March 15, 2007. The initial ballot was conducted from April 17, 2007 – April 26, 2007 and achieved a quorum and sufficient affirmative ballots for passage, but there were four negative ballots cast with comments, necessitating a recirculation ballot.

- Three balloters from the same corporate family (Baltimore Gas and Electric, Constellation Energy, and Constellation Generation Group) suggested that the interpretation was not acceptable because they have equipment that could not meet the requirement to have generators in automatic voltage control mode to control voltage. The drafting team did not modify the interpretation in response to these comments because the standard does allow the transmission operator to exempt generators from compliance with the requirement.

- Tennessee Valley Authority indicated that the interpretation could be misleading when one considers the response to the first question is 'no, unless exempted by the transmission operator.' The drafting team did not modify the interpretation in response to this comment because the interpretation was not intended to re-write or improve the wording of the requirements. The interpretation must be considered in the context of all requirements in the standard, not with respect to individual requirements in isolation.

NERC conducted the recirculation ballot from June 20, 2007 – June 29, 2007 and the ballot results were released on July 3, 2007. The interpretations passed with a quorum of 85.5 % and a weighted segment approval of 98.7 %.

VII. CONCLUSION

NERC requests that the Commission approve the formal interpretations to the following requirements in the Commission-approved NERC Reliability Standards:

- BAL-001-0 — Real Power Balancing Control Performance, Requirement R1
- BAL-003-0 — Frequency Response and Bias, Requirement R3
- BAL-005-0 — Automatic Generation Control, Requirement R17, and
- VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules, Requirements R1 and R2.

as set out in Exhibits A-1, B-1, and C-1, in accordance with Section 215(d)(1) of the FPA and Part 39.5 of the Commission's regulations. NERC requests that these interpretations be made effective immediately upon issuance of the Commission's order in this proceeding.

Respectfully submitted,

/s/ Rebecca J. Michael

Rebecca J. Michael
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
rebecca.michael@nerc.net

Rick Sergel
President and Chief Executive Officer
David N. Cook
Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

<u>**CERTIFICATE OF SERVICE**</u>

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 19th day of December, 2007.

<u>*/s/ Rebecca J. Michael*</u>
Rebecca J. Michael

Attorney for North American Electric Reliability Corporation

Exhibit A-1

Interpretations of Reliability Standards BAL-001-0, Requirement R1 and BAL-003-0, Requirement R3 Proposed for Approval

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Approved by Stakeholders: September 1, 2007

Approved by NERC Board of Trustees: October 23, 2007

Interpretation of BAL-001-0 — Real Power Balancing Control Performance, Requirement 1 and BAL-003-0 — Frequency Response and Bias, Requirement 3

Request for Interpretation received from WECC on June 1, 2007:

Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 1 of BAL-001-0 or Requirement 3 of BAL-003-0?

Interpretation provided by NERC Resources Subcommittee on July 6, 2007:

Requirement 1 of BAL-001 — Real Power Balancing Control Performance, is the definition of the area control error (ACE) equation and the limits established for Control Performance Standard 1 (CPS1).

> **BAL-001-0**
>
> **R1.** Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε12 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

- The WATEC procedural documents ask Balancing Authorities to maintain raw ACE for CPS reporting and to control via WATEC-adjusted ACE.
- As long as Balancing Authorities use raw (unadjusted for WATEC) ACE for CPS reporting purposes, the use of WATEC for control is not in violation of BAL-001 Requirement 1.

Requirement 3 of BAL-003-0 — Frequency Response and Bias deals with Balancing Authorities using Tie-Line Frequency Bias as the normal mode of automatic generation control.

> **BAL-003-0**
>
> **R3.** Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

- Tie-Line Frequency Bias is one of the three foundational control modes available in a Balancing Authority's energy management system. (The other two are flat-tie and flat-frequency.) Many Balancing Authorities layer other control objectives on top of their basic control mode, such as automatic inadvertent payback, CPS optimization, time control (in single BA Interconnections).
- As long as Tie-Line Frequency Bias is the underlying control mode and CPS1 is measured and reported on the associated ACE equation, there is no violation of BAL-003-0 Requirement 3:

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Exhibit A-2

Reliability Standards BAL-001-0a and BAL-003-0a

A. Introduction

1. **Title**: **Real Power Balancing Control Performance**
2. **Number**: BAL-001-0
3. **Purpose**: To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.
4. **Applicability**:

   4.1. Balancing Authorities
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \epsilon_1^2 \text{ or } \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\epsilon_1^2} \le 1$$

The equation for ACE is:

$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

$$AVG_{10-\text{minute}}(ACE_i) \le L_{10}$$

where:

$L_{10} = 1.65 \in_{10} \sqrt{(-10B_i)(-10B_s)}$

ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.

R3. Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement M1 (i.e., Control Performance Standard 1 or CPS1) and Requirement M2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.

R4. Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).

C. Measures

M1. Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12-\text{month}}}{(\in_1)^2}$$

where: ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\dfrac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{-10\text{B}}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error will be used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$\text{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(\text{CF}_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$\text{CF}_{\text{12-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-i})]}{\sum_{i=1}^{12} [n_{(\text{one-minute samples in month})\text{-i}}]}$$

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

M2. Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}})} \right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10}. ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes

= 0 if

$$\left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| \leq L_{10}$$

= 1 if

$$\left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| > L_{10}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Appendix 1-BAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

2.1. Level 1: The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.

2.2. Level 2: The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.

2.3. Level 3: The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.

2.4. Level 4: The Balancing Authority Area's value of CPS1 is less than 85%.

3. Levels of Non-Compliance – CPS2

3.1. Level 1: The Balancing Authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.

3.2. Level 2: The Balancing Authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.

3.3. Level 3: The Balancing Authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.

3.4. Level 4: The Balancing Authority Area's value of CPS2 is less than 75%.

E. Regional Differences

1. The ERCOT Control Performance Standard 2 Waiver approved November 21, 2002.

F. Associated Documents

2. Appendix 2 – Interpretation of Requirement R1 approved October 23, 2007.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2.	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	

Appendix 1-BAL-001-0
CPS1 and CPS2 Data

CPS1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ε_1 used in CPS1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPS1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (525,600 values).

CPS2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than L_{10}.	Retain the values of V used in CPS2 calculation.
ε_{10}	A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.	Retain the value of ε_{10} used in CPS2 calculation.
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value of B_i used in the CPS2 calculation.
B_s	The sum of Frequency Bias of the Balancing Authority Areas in the respective Interconnection. For systems with variable bias, this is equal to the sum of the minimum Frequency Bias Setting.	Retain the value of B_s used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

Appendix 2

Interpretation of Requirement 1

Request: *Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 1 of BAL-001-0?*

Interpretation:

Requirement 1 of BAL-001 — Real Power Balancing Control Performance, is the definition of the area control error (ACE) equation and the limits established for Control Performance Standard 1 (CPS1).

> **BAL-001-0**
>
> **R1.** Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_{12} is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

- The WATEC procedural documents ask Balancing Authorities to maintain raw ACE for CPS reporting and to control via WATEC-adjusted ACE.
- As long as Balancing Authorities use raw (unadjusted for WATEC) ACE for CPS reporting purposes, the use of WATEC for control is not in violation of BAL-001 Requirement 1.

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**
2. **Number:** BAL-001-0
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.
4. **Applicability:**
   4.1. Balancing Authorities
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

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B. Requirements

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \epsilon_1^2 \ or \ \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\epsilon_1^2} \le 1$$

The equation for ACE is:

$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

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R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

$$AVG_{10-\text{minute}}(ACE_i) \le L_{10}$$

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where:

$L_{10}=1.65 \in_{10}\sqrt{(-10B_i)(-10B_s)}$

ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.

R3. Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement M1 (i.e., Control Performance Standard 1 or CPS1) and Requirement M2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.

R4. Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).

C. Measures

M1. Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12-\text{month}}}{(\in_1)^2}$$

where: ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\dfrac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{-10B}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor (CF) becomes:

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$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error will be used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$\text{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(\text{CF}_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$\text{CF}_{\text{12-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-i})]}{\sum_{i=1}^{12} [n_{(\text{one-minute samples in month})-i}]}$$

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

M2. Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}})} \right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10}. ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

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Violation clock-ten-minutes

$$= 0 \text{ if } \left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| \leq L_{10}$$

$$= 1 \text{ if } \left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| > L_{10}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Appendix 1-BAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

2.1. **Level 1:** The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.

2.2. **Level 2:** The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.

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2.3. **Level 3:** The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.

2.4. **Level 4:** The Balancing Authority Area's value of CPS1 is less than 85%.

3. Levels of Non-Compliance – CPS2

3.1. **Level 1:** The Balancing Authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.

3.2. **Level 2:** The Balancing Authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.

3.3. **Level 3:** The Balancing Authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.

3.4. **Level 4:** The Balancing Authority Area's value of CPS2 is less than 75%.

E. Regional Differences

1. The ERCOT Control Performance Standard 2 Waiver approved November 21, 2002.

F. Associated Documents

2. Appendix 2 – Interpretation of Requirement R1 approved October 23, 2007.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2.	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	

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Appendix 1-BAL-001-0
CPS1 and CPS2 Data

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CPS1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ε_1 used in CPS1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPS1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (525,600 values).

CPS2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than L_{10}.	Retain the values of V used in CPS2 calculation.
ε_{10}	A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.	Retain the value of ε_{10} used in CPS2 calculation.
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value of B_i used in the CPS2 calculation.
B_s	The sum of Frequency Bias of the Balancing Authority Areas in the respective Interconnection. For systems with variable bias, this is equal to the sum of the minimum Frequency Bias Setting.	Retain the value of B_s used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

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Appendix 2

Interpretation of Requirement 1

Request: *Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 1 of BAL-001-0?*

Interpretation:

Requirement 1 of BAL-001 — Real Power Balancing Control Performance, is the definition of the area control error (ACE) equation and the limits established for Control Performance Standard 1 (CPS1).

> **BAL-001-0**
>
> **R1.** Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε12 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

- The WATEC procedural documents ask Balancing Authorities to maintain raw ACE for CPS reporting and to control via WATEC-adjusted ACE.
- As long as Balancing Authorities use raw (unadjusted for WATEC) ACE for CPS reporting purposes, the use of WATEC for control is not in violation of BAL-001 Requirement 1.

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A. Introduction

1. **Title:** **Frequency Response and Bias**

2. **Number:** BAL-003-0a

3. **Purpose:**

   This standard provides a consistent method for calculating the Frequency Bias component of ACE.

4. **Applicability:**

   4.1. Balancing Authorities

5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

R1. Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.

R1.1. The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.

R1.2. Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.

R2. Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:

R2.1. The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation. The Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours.

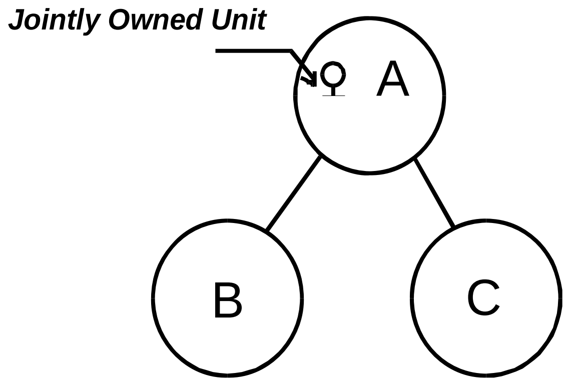
R2.2. The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.

R3. Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

R4. Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.

R4.1. Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C). See the diagram below.

R4.2. The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting.



R5. Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.

R5.1. Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.

R6. A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.

C. Measures

M1. Each Balancing Authority shall perform Frequency Response surveys when called for by the Operating Committee to determine the Balancing Authority's response to Interconnection Frequency Deviations.

D. Compliance

Not Specified.

E. Regional Differences

None identified.

F. Associated Documents

Appendix 1 - Interpretation of Requirement R3 (October 23, 2007).

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R3 approved by BOT on October 23, 2007	

Appendix 1

Interpretation of Requirement 3

Request: *Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 3 of BAL-003-0?*

Interpretation:

Requirement 3 of BAL-003-0 — Frequency Response and Bias deals with Balancing Authorities using Tie-Line Frequency Bias as the normal mode of automatic generation control.

BAL-003-0 **R3.** Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

- Tie-Line Frequency Bias is one of the three foundational control modes available in a Balancing Authority's energy management system. (The other two are flat-tie and flat-frequency.) Many Balancing Authorities layer other control objectives on top of their basic control mode, such as automatic inadvertent payback, CPS optimization, time control (in single BA Interconnections).
- As long as Tie-Line Frequency Bias is the underlying control mode and CPS1 is measured and reported on the associated ACE equation, there is no violation of BAL-003-0 Requirement 3:

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

A. Introduction

1. **Title:** **Frequency Response and Bias**

2. **Number:** BAL-003-0a

3. **Purpose:**

   This standard provides a consistent method for calculating the Frequency Bias component of ACE.

4. **Applicability:**

   4.1. Balancing Authorities

5. **Effective Date:** Immediately after approval of applicable regulatory authorities

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B. Requirements

R1. Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.

R1.1. The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.

R1.2. Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.

R2. Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:

R2.1. The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation. The Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours.

R2.2. The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.

R3. Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

R4. Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.

R4.1. Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C). See the diagram below.

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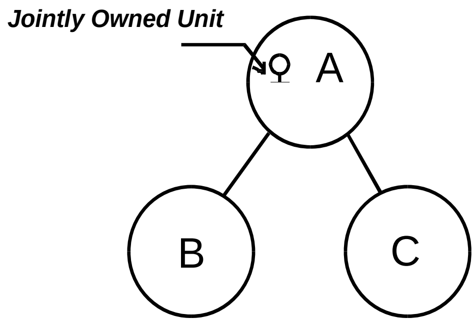
R4.2. The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting.



R5. Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.

R5.1. Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.

R6. A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.

C. Measures

M1. Each Balancing Authority shall perform Frequency Response surveys when called for by the Operating Committee to determine the Balancing Authority's response to Interconnection Frequency Deviations.

D. Compliance

Not Specified.

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E. Regional Differences

None identified.

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F. Associated Documents

Appendix 1 - Interpretation of Requirement R3 (October 23, 2007).

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R3 approved by BOT on October 23, 2007	

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Appendix 1

Interpretation of Requirement 3

Request: *Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 3 of BAL-003-0?*

Interpretation:

Requirement 3 of BAL-003-0 — Frequency Response and Bias deals with Balancing Authorities using Tie-Line Frequency Bias as the normal mode of automatic generation control.

BAL-003-0
R3. Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

- Tie-Line Frequency Bias is one of the three foundational control modes available in a Balancing Authority's energy management system. (The other two are flat-tie and flat-frequency.) Many Balancing Authorities layer other control objectives on top of their basic control mode, such as automatic inadvertent payback, CPS optimization, time control (in single BA Interconnections).
- As long as Tie-Line Frequency Bias is the underlying control mode and CPS1 is measured and reported on the associated ACE equation, there is no violation of BAL-003-0 Requirement 3:

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

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Exhibit A-3

Record of Development of Formal Interpretations for BAL-001-0, Requirement R1 and BAL-003-0, Requirement R3

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Interpretation - BAL-001 and BAL-003

Registered Ballot Body | Reliability Standards Home Page | Drafting Team Rosters

Status
The interpretation of BAL-001 R1 and BAL-003 R3 was approved by stakeholders and the NERC Board of Trustees and is pending regulatory filing.

Purpose / Industry Need
The Western Electricity Coordinating Council (WECC) requests an interpretation applicable to the NERC standard requirements BAL-001-0, R1 and BAL-003-0, R3. Specifically, the WECC asks that NERC conclude and confirm that the WECC's Automatic Time Error Control Procedure (ATEC) does not violate NERC standards. This interpretation would permit the continued use of WECC's ATEC within the Western Interconnection

Proposed Standard	Supporting Documents	Comment Period	Comments Received	Response to Comments
Interpretation of BAL-001-0, R1 and BAL-003-0, R3 Approved for Adoption by Board of Trustees on October 23, 2007 BAL-001-0 and BAL-003 Interpretation (12)				
Announcement (9) Interpretation of BAL-001-0, R1 and BAL-003-0, R3 Posted for 10-day Recirculation Ballot BAL-001-0 and BAL-003 Interpretation (8) (Same as #1)		08/23/07 - 09/01/07 (closed)		Announcement (10) Recirculation Ballot Summary (11)
Announcement (4) Interpretation of BAL-001-0, R1 and BAL-003-0, R3		08/07/07 - 08/16/07 (closed)		Announcement (5) Initial Ballot

Proposed Standard	Supporting Documents	Comment Period	Comments Received	Response to Comments
Posted for 10-day Ballot Window BAL-001-0 and BAL-003 Interpretation (same as #1)				Summary (6) Consideration of Comments (7)
Announcement (3) Request for Interpretation BAL-001-0, R1 and BAL-003-0, R3 Posted for 30-day Pre-ballot Review BAL-001-0 and BAL-003 Interpretation (1)	WECC Request for Interpretation BAL-001-0, R1 and BAL-003-0, R3 (2)	07/09/07 - 08/07/07 (closed)		
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All comments should be forwarded to sarcomm@nerc.net.
Questions? Contact Barbara Bogenrief - barbara.bogenrief@nerc.net or 609-452-8060.

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Interpretation of BAL-001-0 — Real Power Balancing Control Performance, Requirement 1 and BAL-003-0 — Frequency Response and Bias, Requirement 3

Request for Interpretation received from WECC on June 1, 2007:

Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 1 of BAL-001-0 or Requirement 3 of BAL-003-0?

Interpretation provided by NERC Resources Subcommittee on July 6, 2007:

Requirement 1 of BAL-001 — Real Power Balancing Control Performance, is the definition of the area control error (ACE) equation and the limits established for Control Performance Standard 1 (CPS1).

> **BAL-001-0**
>
> **R1.** Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε12 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

- The WATEC procedural documents ask Balancing Authorities to maintain raw ACE for CPS reporting and to control via WATEC-adjusted ACE.
- As long as Balancing Authorities use raw (unadjusted for WATEC) ACE for CPS reporting purposes, the use of WATEC for control is not in violation of BAL-001 Requirement 1.

Requirement 3 of BAL-003-0 — Frequency Response and Bias deals with Balancing Authorities using Tie-Line Frequency Bias as the normal mode of automatic generation control.

> **BAL-003-0**
>
> **R3.** Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

- Tie-Line Frequency Bias is one of the three foundational control modes available in a Balancing Authority's energy management system. (The other two are flat-tie and flat-frequency.) Many Balancing Authorities layer other control objectives on top of their basic control mode, such as automatic inadvertent payback, CPS optimization, time control (in single BA Interconnections).
- As long as Tie-Line Frequency Bias is the underlying control mode and CPS1 is measured and reported on the associated ACE equation, there is no violation of BAL-003-0 Requirement 3:

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Western Electricity Coordinating Council

Louise McCarren
Chief Executive Officer

801.582.0353
louise@wecc.biz

June 1, 2007

Gerard Adamski
Director of Standards
North American Electric Reliability Corporation
Princeton Forrestal Village, 116-390 Village Boulevard
Princeton, New Jersey 08540-5721
609-452-8060 (Voice)

Subject: Western Electricity Coordinating Council (WECC)
Request for Interpretation of NERC Standards BAL-001-01 and BAL-003-01

Dear Gerry,

The Western Electricity Coordinating Council (WECC) requests an interpretation applicable to two current NERC Standard requirements: BAL-001-0, R1 and BAL-003-0, R3. Specifically, the WECC asks that NERC conclude and confirm that the WECC's Automatic Time Error Control Procedure (ATEC) does not violate NERC Standards. This interpretation would permit the continued use of WECC's Automatic Time Error Control Procedure (ATEC) within the Western Interconnection.

Currently, there is some concern within the Western Interconnection that compliance to ATEC would represent non-compliance to the NERC Standards identified above. The WECC is in the process of developing a NERC Regional Standard that would fully define the provisions of ATEC and make the process mandatory for Balancing Authorities in the Western Interconnection. However, the FERC approval of that Standard will most likely not occur until sometime in 2008. The requested interpretation would allow WECC to continue to utilize ATEC as a Regional Criteria until the proposed NERC Regional Standard is approved.

Interpretation Content

The requested interpretation will specifically allow the ATEC term to be included in the NI'_S term of the each Balancing Authority's ACE equation where:

$$NI'_S = NI_S - \frac{II^{on/off\ peak}_{Primary}}{(1-Y)*H}$$

NI_S = Net Interchange Scheduled (MW) in the NERC ACE equation.

$\frac{II^{on/off\ peak}_{Primary}}{(1-Y)*H}$ is the Automatic Time Error Correction

Background
Automatic Time Error Correction has been a reliable regional practice in the WECC since 2003. The procedure results in the elimination of accumulated Time Error and the continuous and equitable reduction of accumulated Inadvertent Interchange. ATEC is not a deviation from the ACE equation as defined in the NERC Standard BAL-001-0. The WECC currently interprets BAL-001-0 as a standard to report and evaluate control performance. ATEC does not inhibit tie line bias criteria. The Balancing Authority still maintains its Interchange Schedule and can respond to Interconnection frequency error. There is no violation of BAL-003-0 R3.

The Federal Energy Regulatory Commission (FERC) recently noted ATEC's effectiveness in minimizing both time error corrections and Inadvertent Interchange.[1] In addition, due to WECC's record of success with its Automatic Time Error Correction Procedure, FERC requested comments on whether it should request NERC to adopt similar Requirements.[2]

Recognition of the WECC ATEC process has not been limited to FERC. The North American Energy Standards Board (NAESB) viewed ATEC as one of two potential solutions to Inadvertent Interchange payback. Extensive discussion by industry stakeholders took place under the auspices of NAESB's Inadvertent Interchange Payback Practice Task Force (IIPTF). The NAESB IIPTF recognized that ATEC had already proven to be effective in the Western Interconnection. IIPTF also considered it an option that could be implemented on a North American-wide basis. However, the stakeholders represented by this NAESB effort could not come to consensus on any of the options being considered. The implementation hurdle faced by the IIPTF for the Western ATEC (WATEC) option was that it required 100% participation from all Balancing Authorities within the Interconnection. The task force was concerned that 100% participation may not be achievable in the Eastern Interconnection. In addition, the task force was of the opinion that because WATEC strictly used reliability parameters, it should be developed in the NERC reliability environment[3].

The ATEC standard has been implemented by all BAs in the Western Interconnection. Although ATEC has been effective in reducing the time error corrections and Inadvertent Interchange, WECC has identified through recent surveys that some Balancing Authorities have not implemented ATEC correctly. WECC has notified these entities and is working with them to resolve their technical issues.

The impact of not receiving the requested interpretation of the NERC Standards BAL-001-0 and BAL-003-0, may result in some Balancing Authorities not participating in the ATEC standard. As previously stated, ATEC requires 100% participation of all Balancing Authorities in the Western Interconnection to be effective. Not operating to ATEC would be detrimental to the Western Interconnection.

[1] Mandatory Reliability Standards for the Bulk-Power System, Notice of proposed rulemaking, Nov. 3, 2006, Federal Register Docket No. RM06-16-000, paragraph 181.
[2] Ibid., paragraph 182.
[3] Final IIPTF Report, Aug 4, 2005, can be downloaded from the NAESB website http://www.naesb.org/weq/weq_iiptf.asp

The WECC greatly appreciates your attention to this matter. If we can provide any additional assistance, please contact Steve Ashbaker at 801-883-6840.

Sincerely,

Louise McCarren,
WECC Chief Executive Officer

Cc: Dave Taylor; Steve Cobb; Dave Hawkins; Steve Ashbaker

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

July 9, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Ballot Window for Withdrawal of WECC Waiver for INT-001 and INT-004; Pre-ballot Window and Ballot Pool for Interpretation of BAL-001 and BAL-003 Open July 9, 2007

The Standards Committee (SC) announces the following:

Ballot Window for Withdrawal of 'WECC Tagging Dynamic Schedules and Inadvertent Payback Waiver' Open July 9–18, 2007

The FERC Order 693 did not include approval of the WECC Tagging Dynamic Schedules and Inadvertent Payback Waiver dated November 21, 2002, which is included in reliability standard INT-001-2 — Interchange Information and INT-004-1 — Dynamic Interchange Transaction Modifications. To remove this waiver as rapidly as possible, the Standards Committee authorized an Urgent Action SAR to Withdraw the WECC Waiver. The proposed modifications to INT-001 and INT-004 are limited to removal of the WECC waiver. The ballot will be open through 8 p.m. (EDT) on Wednesday, July18, 2007.

Pre-ballot Window and Ballot Pool for Interpretation of BAL-001-0, Requirement 1 and BAL-003-0, Requirement 3 both Open July 9, 2007

The Western Electricity Coordinating Council (WECC) submitted a Request for an Interpretation of BAL-001-0 — Real Power Balancing Control Performance and BAL-003-0 — Frequency Response and Bias. The request asked if the use of the WECC Automatic Time Error Correction (WATEC) procedure violates Requirement 1 of BAL-001-0 or Requirement 3 of BAL-003-0.

The Interpretation clarifies that use of the WATEC procedure does not violate either Requirement 1 of BAL-001-0 or Requirement 3 of BAL-003.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EDT) Tuesday, August 7, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp-interpret_bal-001_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EDT) on Tuesday, August 7, 2007.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Maureen E. Long
Standards Process Manager

August 27, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Initial Ballot Window Opens August 27, 2007

The Standards Committee (SC) announces the following standards action:

Initial Ballot Window for Interpretation of BAL-003-0 Requirements R2, R2.2, R5, and R5.1 Opens August 27, 2007

The Electric Reliability Council of Texas (ERCOT) submitted a Request for an Interpretation of BAL-003-0 — Frequency Response and Bias Requirements 2, 2.2, 5, and 5.1. The request asked if there was a conflict between Requirement 2, which allows use of a variable bias setting and Requirement 5, which does not specifically address the use of a variable bias setting.

The Interpretation clarifies that in reliability standard BAL-003-0, Requirements 2 and 5 do not conflict with one another.

The initial ballot for this interpretation is open and will close at 8 p.m. (EDT) on Wednesday, September 5, 2007.

Standards Development Process

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Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Maureen E. Long
Standards Process Manager

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

August 17, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement of Initial Ballot Results

The Standards Committee (SC) announces the following:

Initial Ballot Results for Interpretation of BAL-001-0 R1 and BAL-003-0 R3

The initial ballot for the Interpretation of BAL-001-0 — Real Power Balancing Control Performance, Requirement 1 and BAL-003-0 — Frequency Response and Bias, Requirement 3 was conducted from August 7 through August 16, 2007.

The Interpretation answered the question, “Does the WECC Automatic Time Error Control (WATEC) Procedure violate Requirement 1 of BAL-001-0 or Requirement 3 of BAL-003-0?”

The ballot achieved a quorum; however, there was a negative ballot with a comment, initiating the need to undergo a re-circulation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum: 92.68 %
Approval: 97.91 %

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Reliability Standards

Ballot Results	
Ballot Name:	Interpretation Request - BAL-001-0, R1 and BAL-003-0, R3_in
Ballot Period:	8/7/2007 - 8/16/2007
Ballot Type:	Initial
Total # Votes:	152
Total Ballot Pool:	164
Quorum:	**92.68 % The Quorum has been reached**
Weighted Segment Vote:	97.91 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	49	1	37	0.974	1	0.026	5	6
2 - Segment 2.	9	0.8	8	0.8	0	0	0	1
3 - Segment 3.	34	1	32	1	0	0	2	0
4 - Segment 4.	8	0.8	8	0.8	0	0	0	0
5 - Segment 5.	24	1	17	0.944	1	0.056	6	0
6 - Segment 6.	20	1	15	0.938	1	0.063	3	1
7 - Segment 7.	1	0.1	1	0.1	0	0	0	0
8 - Segment 8.	5	0.2	2	0.2	0	0	2	1
9 - Segment 9.	8	0.6	6	0.6	0	0	0	2
10 - Segment 10.	6	0.4	4	0.4	0	0	1	1
Totals	**164**	**6.9**	**130**	**6.756**	**3**	**0.145**	**19**	**12**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	AEP Service Corp. -- Transmission System AEP	Scott P. Moore	Abstain	
1	Ameren Services Company	Kirit S Shah	Affirmative	
1	American Public Power Association	E. Nick Henery	Affirmative	
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Avista Corp.	Scott Kinney	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins		
1	Consolidated Edison Co. of New York	Edwin E. Thompson PE		
1	Duke Energy	Doug Hils	Affirmative	View

1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair		
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Keyspan LIPA	Richard J. Bolbrock	Abstain	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Abstain	
1	Public Service Company of New Mexico	Keith Nix	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Coop., Inc.	Alan H. Wilkinson	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry G. Akens	Affirmative	
1	Tri-State G & T Association Inc.	Bruce A Sembrick	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Negative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Independent Electricity System Operator	Don Tench	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	

3	Alabama Power Company	Robin Hurst	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Tallahassee	Rusty S. Foster	Affirmative	
3	Consumers Energy Co.	David A. Lapinski	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Gulf Power Company	William F. Pope	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron	Affirmative	
3	Tri-State G & T Association Inc.	Dillwyn H. Ramsay	Abstain	
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
4	Consumers Energy Co.	David Frank Ronk	Affirmative	
4	Florida Municipal Power Agency	William S. May	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 2 of Grant County	Kevin J. Conway	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Alabama Electric Coop. Inc.	Tim Hattaway	Abstain	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Conectiv Energy Supply, Inc.	Richard K Douglass	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Entegra Power Group, LLC	Kenneth Parker	Affirmative	

5	Florida Municipal Power Agency	Douglas Keegan	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	New York Power Authority	Richard J Ardolino	Abstain	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Abstain	
5	PPL Generation LLC	Mark A. Heimbach	Abstain	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K Atkins	Abstain	
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Stephen J. Beuning	Negative	
6	AEP Service Corp.	Dana E. Horton	Abstain	
6	Black Hills Power	Larry Williamson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	First Energy Solutions	Alfred G Roth	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams	Affirmative	
6	Great River Energy	Donna Stephenson	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Robert D. Schwermann	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt Hammond	Affirmative	
6	Southern Company Generation and Energy Marketing	J. Roman Carter	Affirmative	
6	Tampa Electric Co.	Jose Benjamin Quintas		
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
7	Eastman Chemical Company	Lloyd Webb	Affirmative	
8	Energy Mark, Inc.	Howard F. Illian	Abstain	View
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	North Carolina Utilities Commission Public Staff	Jack Floyd	Affirmative	
8	Other	Michehl R. Gent		
8	Prague Power, LLC	William Lohrman	Abstain	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	View
9	Colorado Public Utilities Commission	Jeffrey (Jeff) Hein		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher	Affirmative	
9	North Carolina Utilities Commission	Sam Watson	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
9	Wyoming Public Service Commission	Kathleen A. Lewis		

10	Electric Reliability Council of Texas, Inc.	Sam R. Jones	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	Southwest Power Pool	Charles H. Yeung		
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

609.452.8060 (Voice) - 609.452.9550 (Fax)
116-390 Village Boulevard, Princeton, New Jersey 08540-5721

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot of Interpretation for BAL-001-0 R1 and BAL-003-0 R3

Summary Consideration: The stakeholder comments submitted with initial ballots on the Interpretation of BAL-001-0 — Real Power Balancing Control Performance Requirement 1 and BAL-003-0 — Frequency Response and Bias Requirement 3 did not indicate a need to make any modifications to the interpretation and no changes were made. The Interpretation will proceed to a recirculation ballot.

Segment:	1
Organization:	Duke Energy
Member:	Doug Hils
Comment:	Duke Energy agrees with the interpretation of the Resources Subcommittee which indicates that the WATEC procedure does not violate BAL-001-01 as long as raw ACE used for reporting of CPS compliance (and DCS) does not include the WATEC variable. To the extent that the interpretation requires the Balancing Authorities to calculate raw ACE differently than they had in the past, we would suggest that the WECC be provided some assurance by the WECC Balancing Authorities, perhaps a self-certification, that raw ACE is being calculated in accordance with the standards and the clarification provided in the interpretation.
Response: We agree that the calculation of all BA's CPS and ACE should be validated. In this case, the WECC provided procedural information that showed BAs were instructed to report CPS via raw ACE and control to a WATEC-adjusted ACE. Validation of ACE and CPS should occur as part of normal compliance audits.	
Segment:	6
Organization:	Xcel Energy, Inc.
Member:	David F. Lemmons
Comment:	Xcel Energy is concerned with the interpretation in that it appears that one region will require an ACE calculation that differs from the NERC ACE while all compliance will be determined with the NERC ACE. This causes the potential to violate the NERC standard while operating to the WECC operating requirement. This is an unreasonable position to be put in by the standards organizations. Anytime standards are in conflict with each other, the organizations subject to these standards are put in an untenable position. Reporting of compliance with the standards should be on the basis of the required operating basis. In this exact instance, with WECC requiring operation using a different ACE calculation, WECC entities should be reporting compliance based on the WECC ACE used for operation, not the NERC ACE. If NERC feels that the WECC ACE is not sufficient for reliable operation in meeting CPS and DCS, the the WECC members should not be asked to operate using this method. If NERC is not concerned with this issue, WECC entities should report compliance with CPS and DCS using the WECC ACE.
Response: CPS (as calculated via raw ACE) measures a Balancing Authority's impact on frequency. To measure CPS using another value, would misstate impact on reliability. There are many other similar situations where BAs operate with both a control ACE and a "CPS" ACE. Many BAs employ a different control ACE to pay back inadvertent, maximize CPS, do inadvertent payback when it makes financial sense, to minimize directional changes on generators, etc.. As long as impact on frequency is measured reported via raw ACE, all BAs are measured the same way to the same expectation. We understand WECC is going through the standards drafting process to formalize the WECC procedure as a NERC and FERC approved standard. Once this has occurred, the WATEC control ACE will also be the NERC reporting ACE.	

Segment:	8
Organization:	Energy Mark, Inc.
Member:	Howard F. Illian
Comment:	My concern is with the possible interaction between the current NERC Standards (BAL-001) and the WECC Standard on ATEC. The WECC ATEC Standard does not have a compliance measure associated with it. Therefore, there is no way to insure that the standards will not conflict with each other. If WECC adds a compliance measure at a later date, it could result in a conflict that cannot be corrected without changing the WECC ATEC Standard. If this is necessary, this information should be made available now and considered as part of this interpretation.
Response: We view WATEC as a procedure (rather than a standard) that the WECC uses to achieve a comparability goal. WATEC reduces inadvertent balances and does payback when prices are generally the same. There is a measure associated with BAL-001, that being CPS. As long as BAs calculate and report their performance using raw ACE, their impact on reliability is measured. From a procedural standpoint, an interpretation of a standard is not the mechanism to add compliance elements. We recommend this suggestion be raised as the "Balancing Authority Controls (Project 2007-05)" goes through standard drafting. We understand WECC is going through the standards drafting process to formalize the WECC procedure as a NERC and FERC approved standard. Once this has occurred, the WATEC control ACE will also be the NERC reporting ACE.	
Segment:	9
Organization:	California Energy Commission
Member:	William Mitchell Chamberlain
Comment:	This interpretation is important to allow those Interconnections that wish to use automatic time error correction to do so without fear of being sanctioned. The interpretation does not adversely affect any party in other interconnections.
Response: We agree. Similarly, other Interconnections could develop alternative Time and Payback procedures that achieve their respective objectives. Thank you for your comment.	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

August 23, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Recirculation Ballot Window Opens and Final Ballot Results

The Standards Committee (SC) announces the following:

Recirculation Ballot Window for Interpretation of BAL-001-0 Requirement 1 and BAL-003-0 Requirement 3 Opens August 23, 2007

The Western Electricity Coordinating Council (WECC) submitted a Request for an Interpretation of BAL-001-0 — Real Power Balancing Control Performance and BAL-003-0 — Frequency Response and Bias. The request asked if the use of the WECC Automatic Time Error Correction (WATEC) procedure violates Requirement 1 of BAL-001-0 or Requirement 3 of BAL-003-0.

The Interpretation clarifies that use of the WATEC procedure does not violate either Requirement 1 of BAL-001-0 or Requirement 3 of BAL-003. The initial ballot for this interpretation was conducted from August 7–16, 2007 and achieved a quorum; however, there was a negative ballot with a comment, initiating the need for a recirculation ballot. The drafting team that developed the Interpretation has considered these comments and posted its responses. All members of the ballot pool are encouraged to review the comments submitted with the initial ballot and the responses to those comments.

The recirculation ballot is open through 8 p.m. (EDT) Saturday, September 1, 2007.

Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

In the recirculation ballot, votes are counted by exception only — if members don't indicate a revision to their original votes, the vote remains the same as in the first ballot.

Final Ballot Results for Removal of WECC Waiver from INT-001 and INT-004

The recirculation ballot for the Urgent Action SAR to Withdraw the WECC Waiver (Tagging Dynamic Schedules and Inadvertent Payback Waiver) from INT-001 and INT-004 was conducted from August 13–22, 2007 and the ballot was approved. (Detailed Ballot Results)

Quorum: 78.57 %
Approval: 99.17%

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Maureen E. Long
Standards Process Manager

September 4, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement of Ballot Results

The Standards Committee (SC) announces the following:

Initial Ballot Results for IRO-006-4 — Reliability Coordination — Transmission Loading Relief

The initial ballot for the first phase of modifications to IRO-006-4 — Reliability Coordination — Transmission Loading Relief was conducted from August 20 through August 29, 2007.

The first phase of revisions included working with NAESB to remove all business practices from IRO-006 and then to add measures and compliance elements to support the remaining reliability-related requirements. Future phases of the project will address a broader range of improvements.

The ballot achieved a quorum however there were some negative ballots with comments. The drafting team will review comments submitted with the ballot and will prepare its consideration of those comments. If the drafting team modifies the standard based on comments submitted with the initial ballot, the standard will be posted for an additional comment period; if the drafting team does not make any modifications to the standard, the standard will proceed to a recirculation ballot. (Detailed Ballot Results)

Quorum: 92.70 %
Approval: 93.52 %

Final Ballot Results for Interpretation of BAL-001-0 R1 and BAL-003-0 R3

The recirculation ballot for the Interpretation of BAL-001-0 — Real Power Balancing Control Performance, Requirement 1 and BAL-003-0 — Frequency Response and Bias, Requirement 3 was conducted from August 23 through September 1, 2007 and the ballot was approved. (Detailed Ballot Results)

Quorum: 96.34 %
Approval: 97.21 %

The Interpretation answered the question, "Does the WECC Automatic Time Error Control (WATEC) Procedure violate Requirement 1 of BAL-001-0 or Requirement 3 of BAL-003-0?"

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
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Ballot Results	
Ballot Name:	Interpretation Request - BAL-001-0, R1 and BAL-003-0, R3_rc
Ballot Period:	8/23/2007 - 9/1/2007
Ballot Type:	recirculation
Total # Votes:	158
Total Ballot Pool:	164
Quorum:	**96.34 % The Quorum has been reached**
Weighted Segment Vote:	97.21 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	49	1	40	0.976	1	0.024	5	3
2 - Segment 2.	9	0.8	8	0.8	0	0	0	1
3 - Segment 3.	34	1	32	1	0	0	2	0
4 - Segment 4.	8	0.8	8	0.8	0	0	0	0
5 - Segment 5.	24	1	17	0.944	1	0.056	6	0
6 - Segment 6.	20	1	15	0.882	2	0.118	3	0
7 - Segment 7.	1	0.1	1	0.1	0	0	0	0
8 - Segment 8.	5	0.3	3	0.3	0	0	2	0
9 - Segment 9.	8	0.6	6	0.6	0	0	0	2
10 - Segment 10.	6	0.5	5	0.5	0	0	1	0
Totals	**164**	**7.1**	**135**	**6.902**	**4**	**0.198**	**19**	**6**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	AEP Service Corp. -- Transmission System AEP	Scott P. Moore	Abstain	
1	Ameren Services Company	Kirit S Shah	Affirmative	
1	American Public Power Association	E. Nick Henery	Affirmative	
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Avista Corp.	Scott Kinney	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Consolidated Edison Co. of New York	Edwin E. Thompson PE		
1	Duke Energy	Doug Hils	Affirmative	View

1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Keyspan LIPA	Richard J. Bolbrock	Abstain	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Public Service Company of New Mexico	Keith Nix	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Abstain	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Coop., Inc.	Alan H. Wilkinson	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry G. Akens	Affirmative	
1	Tri-State G & T Association Inc.	Bruce A Sembrick	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Negative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Independent Electricity System Operator	Don Tench	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	

3	Alabama Power Company	Robin Hurst	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Tallahassee	Rusty S. Foster	Affirmative	
3	Consumers Energy Co.	David A. Lapinski	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Gulf Power Company	William F. Pope	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Abstain	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron	Affirmative	
3	Tri-State G & T Association Inc.	Dillwyn H. Ramsay	Abstain	
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
4	Consumers Energy Co.	David Frank Ronk	Affirmative	
4	Florida Municipal Power Agency	William S. May	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 2 of Grant County	Kevin J. Conway	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Alabama Electric Coop. Inc.	Tim Hattaway	Abstain	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Conectiv Energy Supply, Inc.	Richard K Douglass	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Entegra Power Group, LLC	Kenneth Parker	Affirmative	

5	Florida Municipal Power Agency	Douglas Keegan	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	New York Power Authority	Richard J Ardolino	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Abstain	
5	PPL Generation LLC	Mark A. Heimbach	Abstain	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K Atkins	Abstain	
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Stephen J. Beuning	Negative	
6	AEP Service Corp.	Dana E. Horton	Abstain	
6	Black Hills Power	Larry Williamson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	First Energy Solutions	Alfred G. Roth	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams	Affirmative	
6	Great River Energy	Donna Stephenson	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Robert D. Schwermann	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt Hammond	Affirmative	
6	Southern Company Generation and Energy Marketing	J. Roman Carter	Affirmative	
6	Tampa Electric Co.	Jose Benjamin Quintas	Negative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
7	Eastman Chemical Company	Lloyd Webb	Affirmative	
8	Energy Mark, Inc.	Howard F. Illian	Abstain	View
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	North Carolina Utilities Commission Public Staff	Jack Floyd	Affirmative	
8	Other	Michehl R. Gent	Affirmative	
8	Prague Power, LLC	William Lohrman	Abstain	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	View
9	Colorado Public Utilities Commission	Jeffrey (Jeff) Hein		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher	Affirmative	
9	North Carolina Utilities Commission	Sam Watson	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
9	Wyoming Public Service Commission	Kathleen A. Lewis		

10	Electric Reliability Council of Texas, Inc.	Sam R. Jones	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

609.452.8060 (Voice) - 609.452.9550 (Fax)
116-390 Village Boulevard, Princeton, New Jersey 08540-5721

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Approved by Stakeholders: September 1, 2007

Approved by NERC Board of Trustees: October 23, 2007

Interpretation of BAL-001-0 — Real Power Balancing Control Performance, Requirement 1 and BAL-003-0 — Frequency Response and Bias, Requirement 3

Request for Interpretation received from WECC on June 1, 2007:

Does the WECC Automatic Time Error Control Procedure (WATEC) violate Requirement 1 of BAL-001-0 or Requirement 3 of BAL-003-0?

Interpretation provided by NERC Resources Subcommittee on July 6, 2007:

Requirement 1 of BAL-001 — Real Power Balancing Control Performance, is the definition of the area control error (ACE) equation and the limits established for Control Performance Standard 1 (CPS1).

> **BAL-001-0**
>
> **R1.** Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε12 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

- The WATEC procedural documents ask Balancing Authorities to maintain raw ACE for CPS reporting and to control via WATEC-adjusted ACE.
- As long as Balancing Authorities use raw (unadjusted for WATEC) ACE for CPS reporting purposes, the use of WATEC for control is not in violation of BAL-001 Requirement 1.

Requirement 3 of BAL-003-0 — Frequency Response and Bias deals with Balancing Authorities using Tie-Line Frequency Bias as the normal mode of automatic generation control.

> **BAL-003-0**
>
> **R3.** Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.

- Tie-Line Frequency Bias is one of the three foundational control modes available in a Balancing Authority's energy management system. (The other two are flat-tie and flat-frequency.) Many Balancing Authorities layer other control objectives on top of their basic control mode, such as automatic inadvertent payback, CPS optimization, time control (in single BA Interconnections).
- As long as Tie-Line Frequency Bias is the underlying control mode and CPS1 is measured and reported on the associated ACE equation, there is no violation of BAL-003-0 Requirement 3:

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Exhibit B-1

Interpretation of Reliability Standard BAL-005-0, Requirement R17 Proposed for Approval

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interpretation of BAL-005-1 Automatic Generation Control, R17

Request for Interpretation Received from R. W. Beck on December 21, 2006

We are currently interpreting this as saying that the only devices that need to be calibrated are the time error and frequency devices (first sentence of R17) and that the list of device accuracy in the second sentence of R17 is simply the design accuracy of the devices listed and that those devices do not need to be calibrated on an annual basis (except the digital frequency transducer which is covered as a "frequency device" in the first sentence). Can you tell us if this is a correct interpretation?

BAL-005-1

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	**Accuracy**
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

Interpretation Provided by NERC Frequency Task Force:

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to "annually check and calibrate" the devices listed in the table, unless they are included in the control center time error and frequency devices.

Exhibit B-2

Reliability Standard BAL-005-0a

A. Introduction

1. **Title:** **Automatic Generation Control**

2. **Number:** BAL-005-0a

3. **Purpose:**

   This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Generator Operators

   4.3. Transmission Operators

   4.4. Load Serving Entities

5. **Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

Appendix 1 - Interpretation of Requirement R17 (May 2, 2007)

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Revised

Appendix 1 - Interpretation of Requirement R17 (May 2, 2007):

Request: We are currently interpreting R17 as saying that the only devices that need to be calibrated are the time error and frequency devices (first sentence of R17) and that the list of device accuracy in the second sentence of R17 is simply the design accuracy of the devices listed and that those devices do not need to be calibrated on an annual basis (except the digital frequency transducer which is covered as a "frequency device" in the first sentence). Can you tell us if this is a correct interpretation?

Interpretation: BAL-005-0, Requirement R17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to “annually check and calibrate” does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to “annually check and calibrate” the devices listed in the table, unless they are included in the control center time error and frequency devices.

A. Introduction

1. **Title:** **Automatic Generation Control**

2. **Number:** BAL-005-0a

3. **Purpose:**

   This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Generator Operators

   4.3. Transmission Operators

   4.4. Load Serving Entities

5. **Effective Date:** Immediately after approval of applicable regulatory authorities.

Deleted: April 1, 2005

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

Deleted: February 8

Deleted: 2005

Deleted: Effective Date: April 1, 2005

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical

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locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be

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retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

Appendix 1 - Interpretation of Requirement R17 (May 2, 2007)

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Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Revised

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Appendix 1 - Interpretation of Requirement R17 (May 2, 2007):

Request: We are currently interpreting R17 as saying that the only devices that need to be calibrated are the time error and frequency devices (first sentence of R17) and that the list of device accuracy in the second sentence of R17 is simply the design accuracy of the devices listed and that those devices do not need to be calibrated on an annual basis (except the digital frequency transducer which is covered as a "frequency device" in the first sentence). Can you tell us if this is a correct interpretation?

Interpretation: BAL-005-0, Requirement R17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to "annually check and calibrate" the devices listed in the table, unless they are included in the control center time error and frequency devices.

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Exhibit B-3

Record of Development of Formal Interpretation for BAL-005-0, Requirement R17

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Interpretation - BAL-005 - Automatic Generation Control

Registered Ballot Body | Reliability Standards Home Page

Status

The Standards Committee has posted the results and the consideration of ballot comments from interpretation for standard BAL-005-0, Requirement 17. The recirculation ballot results have been posted.

The Board of Trustees will consider adopting the Interpretation for BAL-005-0, Requirement 17 at its May 2, 2007 meeting.

Purpose / Industry Need

In accordance with the Reliability Standards Development Procedure, the interpretation must be posted for a 30-day pre-ballot review, and then balloted. There is no public comment period for an interpretation. Balloting will be conducted following the same method used for balloting standards. If the interpretation is approved by its ballot pool, then the interpretation will be appended to the standard and will become effective when adopted by the NERC Board of Trustees and approved by the applicable regulatory authorities. The interpretation will remain appended to the standard until the standard is revised through the normal standards development process. When the standard is revised, the clarifications provided by the interpretation will be incorporated into the revised standard.

Proposed Standard	Supporting Documents	Comment Period	Comments Received	Response to Comments
Request for Interpretation BAL-005-0, Requirement 17 - Automatic Generation Control Posted for Board of Trustees Adoption May 2, 2007 BAL-005-1 (10)				
Announcement (8) Request for Interpretation BAL-005-0, Requirement 17 - Automatic Generation Control Posted for 10-day Recirculation Ballot Window April 17 through April 26, 2007 BAL-005-0, Requirement 17 - Clean (same as 1)		04/17/07 - 04/26/07 10-day Recirculation Ballot Window Closed		Recirculation Ballot Results (9)

Announcement (5) Request for Interpretation BAL-005-0, Requirement 17 - Automatic Generation Control Posted for 10-day Ballot Window March 19 through March 30, 2007 BAL-005-0, Requirement 17 - Clean (same as 1)	R.W. Beck Request for Interpretation (same as 4) BAL-005-0, Requirement 17	03/19/07 - 03/30/07 10-day Ballot Window Closed		Initial Ballot Results (7) Consideration of Comments (6)
Announcement (3) Request for Interpretation BAL-005-0, Requirement 17 - Automatic Generation Control Posted for 30-day Pre-ballot Review February 7 through March 9, 2007 BAL-005-0, Requirement 17 - Clean (1) | Redline (2)	R.W. Beck Request for Interpretation (4) BAL-005-0, Requirement 17	02/07/07 - 03/9/07 30-day Pre-ballot Review Closed		

To download a file click on the file using your right mouse button, then save it to your computer in a directory of your choice.

Documents in the PDF format require use of the Adobe Reader® software. Free Adobe Reader® software allows anyone view and print Adobe Portable Document Format (PDF) files. For more information download the Adobe Reader User Guide.

All comments should be forwarded to sarcomm@nerc.com.
Questions? Contact Barbara Bogenrief - barbara.bogenrief@nerc.net or 609-452-8060.

A. Introduction

1. **Title:** **Automatic Generation Control**

2. **Number:** BAL-005-1

3. **Purpose:**

   This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Generator Operators

   4.3. Transmission Operators

   4.4. Load Serving Entities

5. **Proposed Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority’s AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority’s ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Time Frame

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

Interpretation to BAL-005-1 Requirement 17

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

Interpretation of BAL-005-1 Requirement 17

BAL-005-0, Requirement 17 requires that the Balancing Authority to check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to "annually check and calibrate" the devices listed in the table, unless they are included in the control center time error and frequency devices.

A. Introduction

1. **Title:** **Automatic Generation Control**

2. **Number:** BAL-005-~~0~~1

3. **Purpose:**

   This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Generator Operators

   4.3. Transmission Operators

   4.4. Load Serving Entities

5. **Proposed Effective Date:** ~~April 1, 2005~~Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

~~**Interpretation (to be published in the standard if approved)**~~

~~BAL-005-0, Requirement 17 requires that the Balancing Authority to check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.~~

~~The table represents the design accuracy of the listed devices. There is no requirement within the standard to "annually check and calibrate" the devices listed in the table, unless they are included in the control center time error and frequency devices.~~

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

Interpretation to BAL-005-1 Requirement 17

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

Interpretation of BAL-005-1 Requirement 17

BAL-005-0, Requirement 17 requires that the Balancing Authority to check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to "annually check and calibrate" the devices listed in the table, unless they are included in the control center time error and frequency devices.

Maureen E. Long
Standards Process Manager

February 7, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement:
Pre-ballot Window and Ballot Pool Open on February 7, 2007

The Standards Committee announces the following standards actions:

Pre-ballot Window and Ballot Pool Open on February 7, 2007 for Interpretation of BAL-005 Requirement 17

R. W. Beck, Inc., requested a formal interpretation to BAL-005-0 — Automatic Generation Control, Requirement 17. The Resources Subcommittee, working with NERC staff, developed the interpretation.

BAL-005-0, Requirement 17 states:

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, Mvar, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

We are currently interpreting this as saying that the only devices that need to be calibrated are the time error and frequency devices (first sentence of R17) and that the list of device accuracy in the second sentence of R17 is simply the design accuracy of the devices listed and that those devices do not need to be calibrated on an annual basis (except the digital frequency transducer which is covered as a "frequency device" in the first sentence). Can you tell us if this is a correct interpretation?

Interpretation (to be published in the standard if approved)
BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to annually check and calibrate the devices listed in the table, unless they are included in the control center time error and frequency devices.

Justification

- The first sentence in Requirement 17 was taken from Operating Policy 1 and relates specifically and solely to time error and frequency devices.
- The table was extracted from a guide in the retired Policy 1, Appendix 1H, and includes recommended accuracy values for all monitoring equipment.

In accordance with the *Reliability Standards Development Procedure*, the interpretation must be posted for a 30-day pre-ballot review, and then balloted. There is no public comment period for an interpretation. Balloting will be conducted following the same method used for balloting standards. If the interpretation is approved by its ballot pool, then the interpretation will be appended to the standard and will become effective when adopted by the NERC Board of Trustees and approved by the applicable regulatory authorities. The interpretation will remain appended to the standard until the standard is revised through the normal standards development process. When the standard is revised, the clarifications provided by the interpretation will be incorporated into the revised standard.

The Interpretation of BAL-005-0 Requirement 17 is posted for a 30-day pre-ballot review. A ballot pool to vote on the interpretation has been formed and will remain open through 8 a.m. (EST) Friday, March 9, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server[1]." The list server for this ballot pool is called: bp-bal-005_interpret_in@nerc.com

Before joining the ballot pool, please make sure that you will be available during the ballot window to cast your ballot. The initial ballot for the interpretation to BAL-005 will be conducted from 8 a.m. (EST) on Friday, March 9 through 8 p.m. (EST) Monday, March 19, 2006.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

[1] For assistance in using a list server, contact Barbara Bogenrief at 609-452-8060.

Request for an Interpretation:

Received from Sean Croup
Senior Consulting Engineer
R. W. Beck, Inc.
December 21, 2007

The question is related to BAL-005-0 R17 which reads as follows:

> R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

We are currently interpreting this as saying that the only devices that need to be calibrated are the time error and frequency devices (first sentence of R17) and that the list of device accuracy in the second sentence of R17 is simply the design accuracy of the devices listed and that those devices do not need to be calibrated on an annual basis (except the digital frequency transducer which is covered as a "frequency device" in the first sentence). Can you tell us if this is a correct interpretation?

The impact of the alternate interpretation is that there are quite a number of RTUs, MW, MVAR and voltage transducers, potential transformers (PTs) and current transformers (CTs) throughout any power system, potentially thousands, that if they needed to be calibrated annually would be a burden on utilities. For instance, a single transmission line or transformer will likely have 24 or more current transformers associated with it. If a utility owns a hundred or so transmission lines and transformers, then at least 2400 CTs would need to be calibrated annually with the alternate interpretation.

Another way to interpret the standard is that the RTUs, transducers, PTs and CTs referred to in the standard are those only associated with frequency and time error measurement, but that is not clear.

It would be helpful to indicate 1) which RTUs, MW, MVAR and Voltage transducers, CTs and PTs does the standard apply to, all of them in the bulk system, or just those associated with frequency and time error measurement, and 2) does the annual calibration apply to only the time error and frequency devices or to all of the devices listed in R.17, including transducers, PTs and CTs.

Maureen E. Long
Standards Process Manager

April 17, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: One Initial Ballot Window and Three Recirculation Ballot Windows Open on April 17, 2007

The Standards Committee (SC) announces the following standards actions:

Initial Ballot Window Open April 17–26, 2007

Interpretation of VAR-002-1 Requirements 1 and 2

The initial ballot on the Interpretation of VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules, Requirements 1 and 2 will be conducted from 8 a.m. (EDT) on Tuesday, April 17 through 8 p.m. (EDT) Thursday, April 26, 2007.

This interpretation clarifies the intent of the use of the phrase, "operation in the automatic voltage control mode" in Requirements 1 and 2.

Three Recirculation Ballot Windows Open April 17–26, 2007

Each of the following three recirculation ballots will be conducted from 8 a.m. (EDT) on Tuesday, April 17 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the associated ballot pools are encouraged to review the comments submitted with the initial ballots, and the associated drafting team's responses to those comments.

Members of the ballot pools may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

In the recirculation ballot, votes are counted by exception only — if members don't indicate a revision to their original votes, the vote remains the same as in the first ballot.

Balance Resources and Demand Standards

The recirculation ballot for the following set of Balance Resources and Demand standards will be conducted from 8 a.m. (EDT) on Tuesday, April 17 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the ballot pool are encouraged to review the comments submitted with the initial ballot, and the drafting team's responses to those comments.

BAL-007-1 — Balance of Resources and Demand
BAL-008-1 — Frequency and Area Control Error
BAL-009-1 — Actions to Return Frequency to within Frequency Trigger Limits
BAL-010-1 — Frequency Bias Settings
BAL-011-1 — Frequency Limits

These standards require entities to maintain interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e., normal and abnormal), to prevent unwarranted load shedding and to prevent frequency-related cascading collapse of the interconnected grid. The ballot for the above set of standards also includes the Balance Resources and Demand Implementation Plan.

Nuclear Plant Interface Coordination Standard (NUC-001)

The recirculation ballot for the Nuclear Plant Interface Coordination (NUC-001-1) standard will be conducted from 8 a.m. (EDT) on Tuesday, April 17, 2007 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the ballot pool are encouraged to review the comments submitted with the initial ballot, and the drafting team's responses to those comments.

This standard requires coordination between nuclear plant generator operators and transmission entities to ensure safe operation and shutdown of nuclear plants. The ballot for this standard also includes the Nuclear Plant Interface Coordination Implementation Plan.

Interpretation of BAL-005 — Automatic Generation Control Requirement 17

The recirculation ballot for the Interpretation of BAL-005-0 — Automatic Generation Control Requirement 17 will be conducted from 8 a.m. (EDT) on Tuesday, April 17, 2007 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the ballot pool are encouraged to review the comments submitted with the initial ballot, and the drafting team's responses to those comments.

The interpretation clarifies that the Balancing Authority is required to check and calibrate its control room time error and frequency devices against a common reference at least annually, but the requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Interpretation of BAL-005-1 — Automatic Generation Control - Requirement 17

Summary Consideration: While several commenters made suggestions to improve the overall wording of the interpretation, most stakeholders agreed with the interpretation and the drafting team did not make any modifications to the interpretation. There is a project in Reliability Standards Development Plan 2007-2009 that includes the revision of BAL-005-1. The suggestions for improvements to the language of the interpretation can be used when BAL-005-1 is revised.

Organization:	American Transmission Company, LLC
Member:	Douglas F. Johnson
Comment:	Comments: ATC agrees with NERC's interpretation of Requirement 17 but feel that it needs additional clarity. We request that NERC consider our suggested language to its interpretation. Existing language: The table represents the design accuracy of the listed devices. Suggested language: The table represents the design accuracy of metering devices that provide data to the ACE equation. The suggested language does not alter NERC's interpretation but provides additional clarity for the list of devices.
Response: We appreciate the suggestion. Our concern is that the table includes items (MVAr and Voltage transducers) that don't provide data to the ACE equation. While we agree that the other inputs (tie lines) need attention, they are addressed in other portions of the standard (hourly checks, etc.). The underlying question dealt with the calibration of time and frequency devices. We should note that the BAL standards will be revised soon and your suggestions will be used to make the next revisions clearer.	
Organization:	Baltimore Gas & Electric Company
Member:	John J. Moraski
Comment:	1. The requirement is subject to multiple interpretations and by eliminating the ambiguity with it will be easier to measure compliance. 2. The interpretation is narrow, limiting the "check and calibrate" requirement to "control room time error and frequency devices", which is beneficial to entities, such as CECD, that have customers with devices in multiple locations throughout the interconnection that are remote from the control center.
Response: We appreciate the comment and agree that clarity is important. While devices in the field are important, this particular standard deals with the primary time and frequency devices used by the balancing authority operator. As noted above, the BAL standards will be revised soon and your suggestions will be used to make the next revisions clearer.	
Organization:	Nova Scotia Power Inc.
Member:	David D. Little
Comment:	We agree with the R W Beck Inc. interpretation: that the only devices that need to be calibrated are the time error and frequency devices.
Response: Thank you for your support.	

Organization:	Westar Energy
Member:	Allen Klassen
Comment:	Vote to approve although it is poorly worded. The LOCATION is not the important factor for this equipment, it's whether it is used as input for Automatic Generation Control (AGC) such as input to the ACE equation. This equipment may not be anywhere near the Control Room!
Response: We agree the device could physically be located outside the control room. This particular standard deals with the primary time and frequency devices used by the balancing authority operator. As noted above, the BAL standards will be revised soon and your suggestions will be used to make the next revisions clearer.	
Organization:	New Brunswick System Operator
Member:	Alden Briggs
Comment:	NBSO supports this interpretation to the standard provided it refers to automatic voltage control, and not constant MVAR or constant PF control. The 3 control modes are different operations, and the standard refers to voltage control only. In additon, the term AVR is not defined by NERC in their golssary.
Response: Thanks for your comment. This standard deals with the inputs to time, frequency and ACE control.	
Organization:	City Public Service of San Antonio
Member:	Edwin Les Barrow
Comment:	I don't know what button to select for an interpretation, but I believe the RTUs, transducers, PTs and CTs referenced in the standard are only those associated with frequency and time error measurement.
Response: We appreciate the comment. Some people were interpreting this requirement as all such devices in the field. As noted above, the BAL standards will be revised soon and your suggestions will be used to make the next revisions clearer.	
Organization:	Florida Power Corporation
Member:	Lee Schuster
Comment:	Progress Energy believes the standard and/or its interpretation should also recognize more clearly that there are digital frequency transducers which employ satellite GPS for reference and the equipment vendor indicates there are no field calibration procedures which can be performed by end-user; in such a case, calibration is not necessary or possible.
Response: We agree with this comment and that where solid state equipment does not allow output adjustment; calibration is interpreted to mean verification and replacement if outside of tolerances. As noted above, the BAL standards will be revised soon and your suggestions will be used to make the next revisions clearer.	
Organization:	New York Power Authority
Member:	Christopher Lawrence de Graffenried
Comment:	CP-9 agrees with the interpretation provided by NERC
Response: Thank you for your support.	

Organization:	Niagara Mohawk (National Grid Company)
Member:	Michael Schiavone
Comment:	I support this interpretation to the standard provided it refers to automatic voltage control, and not constant MVAR or constant PF control. The 3 control modes are different operations, and the standard refers to voltage control only. In additon, the term AVR is not defined by NERC in their golssary
Response: Thanks for this comment. This standard deals with the inputs to time, frequency and ACE control.	
Organization:	Public Utility District No. 2 of Grant County
Member:	Kevin J. Conway
Comment:	If a standard is required to have an interpretation, it should immediately be cause for review of the standard. We do not disagree with the interpretation on this particular issue, however the interpretation becomes part of the standard until it is reviewed. This is a dangerous practice, and could be abused.
Response: We appreciate the comment.	
Organization:	Progress Energy Carolinas
Member:	Wayne Lewis
Comment:	Progress Energy believes the standard and/or its interpretation should also recognize more clearly that there are digital frequency transducers which employ satellite GPS for reference and the equipment vendor indicates there are no field calibration procedures which can be performed by end-user; in such a case, calibration is not necessary or possible.
Response: We agree with this comment and that where solid state equipment does not allow output adjustment; calibration is interpreted to mean verification and replacement if outside of tolerances. As noted above, the BAL standards will be revised soon and your suggestions will be used to make the next revisions clearer.	
Organization:	Energy Mark, Inc.
Member:	Howard F. Illian
Comment:	Check and Calibrate: I disagree with the interpretation of the standard as clarified. There are two clarifying statements included within the interpretation. The first of these is the standard only applies to devices in the control room. The second is the standard only applies to time error and frequency devices inside the control room. The following discussion provides the basis for my disagreement. There are four possible levels of equipment inclusion for interpretation when applying this standard for the purpose to “annually check and calibrate” equipment. These levels are discussed in order below: Level 1: Only time error and frequency devices in the control room are subject to this rule. This interpretation does not make sense to me because, even if the intent was to apply it only to frequency and time error devices, there are requirements that a back-up or alternate source be available for frequency measurement when the primary source is down or unavailable. This back-up or alternate source will seldom be located in the control

	room. Therefore, the recommended interpretation could result in the use of unreliable information for time error and frequency whenever the primary source is down or unavailable. When the primary frequency source is unavailable, this will result in poor or at best unreliable, situational awareness for the system operator. The better alternative, if a Level 1 interpretation is used, would be to require that all time error and frequency devices and the telemetry channels, scaling transducers, and primary sensors be subject to the "annual check and calibrate" requirement whether or not they are located in the control room or control center. Level 2: Devices used as part of the calculation of the Balancing Authority ACE Equation are subject to the "annual check and calibrate" requirement. The request for interpretation incorrectly implies that there are only two alternate ways to interpret the standard and offers the second alternative to "annually check and calibrate" all devices as unreasonable. On the other hand, if the standard can be interpreted in many ways, the apparently unreasonable requirement to "annually check and calibrate" relevant devices becomes not only more reasonable but more also desirable. The ACE Equation is used as the basis for coordinated control on the North American interconnections. Its implementation requires not only accurate time error and frequency measurement, but also accurate measurement of the net flow on the tie-lines connecting with other Balancing Authorities. To insure acceptable implementation of the ACE Equation and insure properly coordinated control for an interconnection, it makes little sense to require accurate time error and frequency information without also requiring accurate tie-flow information. This interpretation would also explain why the standard specifies information on devices not used for time error or frequency measurement, but also includes devices necessary to measure power flow on tie-lines connecting a Balancing Authority to the rest of the interconnection. If this interpretation is selected, then it should also include the check and calibration of the intervening equipment used to transmit the tie-flow information to the control center. This would include the checking of turns-ratios and scaling factors included in the software in addition to the sensing equipment itself. Level 3: Include the measurements of generator output in the "annual check and calibrate" requirement. If the requirement is extended beyond the ACE Equation and intended to apply to the accurate operation of the Automatic Generation Control System, then the information required to measure generator output would be included in addition to the tie-line information. This would significantly increase the quantity of equipment that would be subject to the requirement, but it would still only include a small fraction of the measurement equipment on the system referred to in the request. Level 4: Include all measurement equipment on the interconnection. As stated in the request, this interpretation would be an unreasonable burden on the industry. Recommendation: The standard should be interpreted as described in Level 2 above applying the standard to all devices supporting the ACE Equation. This interpretation would not put an unreasonable burden on the industry. It would insure that the methods the industry has selected to implement its coordinated control philosophy would be accurate. Finally, it would insure the measurement methods used to determine each participant's contributions to coordinated control would be accurately measured with the reliability measures currently implemented such as CPS1. As long as the Balancing Authority is able to meet the performance measures in the standards that apply, it would be unnecessary to go as far as Level 3 because the accuracy of a Balancing Authority's AGC should be decided internal to that Balancing Authority.

Response: We appreciate the thoughtful comments. We disagree that the intent of the standards was that all inputs to the ACE equation

require annual calibration. This "Version 0" requirement evolved from a conversion from a previous guide that recommended annual calibration of devices in the field. The V0 process was not intended to convert good practices to mandatory requirements. The underlying reason there is a "metering error" term in the ACE equation is that there is inherent error that is subject to hourly review and corrective steps taken when problems are found. As noted above, the BAL standards will be revised soon and your suggestions will be used to make the next revisions clearer.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Ballot Results	
Ballot Name:	Interpretation Request for BAL-005_in
Ballot Period:	3/19/2007 - 3/30/2007
Ballot Type:	Initial
Total # Votes:	198
Total Ballot Pool:	235
Quorum:	**84.26 % The Quorum has been reached**
Weighted Segment Vote:	97.10 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	#	
1 - Segment 1.	70	1	52	0.963	2	0.037	4	12
2 - Segment 2.	10	0.9	9	0.9	0	0	0	1
3 - Segment 3.	52	1	41	0.976	1	0.024	2	8
4 - Segment 4.	16	1	12	0.923	1	0.077	0	3
5 - Segment 5.	39	1	27	1	0	0	3	9
6 - Segment 6.	24	1	19	1	0	0	2	3
7 - Segment 7.	3	0.3	3	0.3	0	0	0	0
8 - Segment 8.	6	0.6	5	0.5	1	0.1	0	0
9 - Segment 9.	7	0.7	7	0.7	0	0	0	0
10 - Segment 10.	8	0.7	7	0.7	0	0	0	1
Totals	**235**	**8.2**	**182**	**7.962**	**5**	**0.238**	**11**	**37**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	AEP Service Corp. -- Transmission System AEP	Scott P. Moore	Affirmative	
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Alliant Energy	Kenneth Goldsmith	Affirmative	
1	Ameren Services Company	Peggy Ladd	Affirmative	
1	American Public Power Association	E. Nick Henery	Affirmative	
1	American Transmission Company, LLC	Douglas F. Johnson	Affirmative	View
1	Avista Corp.	Scott Kinney	Affirmative	
1	Baltimore Gas & Electric Company	John J. Moraski	Affirmative	View

1	Basin Electric Power Cooperative	Mike Risan	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Central Maine Power Company	David Mark Conroy	Abstain	
1	Consolidated Edison Co. of New York	Edwin E. Thompson PE	Affirmative	
1	Dominion Virginia Power	William L. Thompson		
1	Duke Energy	Doug Hils	Affirmative	
1	Duquesne Light Co.	Bob McClelland	Abstain	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer		
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Brian F. Thumm	Affirmative	
1	JEA	Ted E. Hobson	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Keyspan LIPA	Richard J. Bolbrock	Affirmative	
1	LG&E Energy Transmission Services	Bradley Young		
1	Lincoln Electric System	Doug Bantam		
1	Manitoba Hydro	Robert G. Coish	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	National Grid USA	Herbert Schrayshuen	Negative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Negative	
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Nova Scotia Power Inc.	David D. Little	Affirmative	View
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Melvin H. Perkins	Affirmative	
1	Oncor	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson		
1	Pacific Gas and Electric Company	Chifong L. Thomas	Abstain	
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Verne B. Ingersoll	Affirmative	
1	Public Service Company of New Mexico	Keith Nix	Affirmative	
1	Public Service Electric and Gas Co.	Colin Loxley	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown		
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Affirmative	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	South Carolina Electric & Gas Co.	Lee N. Xanthakos		
1	Southern California Edison Co.	Dana Cabbell	Abstain	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison		

1	Southwest Transmission Coop., Inc.	Alan H. Wilkinson		
1	Southwestern Power Administration	Stanley Mason	Affirmative	
1	Tampa Electric Co.	Paul Michael Davis	Affirmative	
1	Tennessee Valley Authority	Larry G. Akens	Affirmative	
1	Tri-State G & T Association Inc.	Bruce A Sembrick		
1	Westar Energy	Allen Klassen	Affirmative	View
1	Western Area Power Administration - CM WACM	Mark E. Fidrych		
1	Western Farmers Electric Coop.	Alan Derichsweiler		
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Independent Electricity System Operator	Don Tench	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Rocky Mountain-Desert Southwest Reliability Center	Frank R. McElvain		
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Tallahassee	Rusty S. Foster		
3	City Public Service of San Antonio	Edwin Les Barrow	Negative	View
3	Cleco Utility Group	Bryan Y Harper	Abstain	
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy Co.	David A. Lapinski	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander	Affirmative	
3	Florida Power & Light Co.	W.R. Schoneck	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Gulf Power Company	William F. Pope	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Ronald Dacombe	Affirmative	
3	MAPPCOR	Peter Koegel		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	View

3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	View
3	Oklahoma Gas and Electric Co.	Gary Clear	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Reliant Energy Services	John Meyer		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	SaskPower	Jeff Gienow	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron	Affirmative	
3	Tri-State G & T Association Inc.	Dillwyn H. Ramsay		
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alabama Electric Coop. Inc.	Kenneth Skroback	Affirmative	
4	American Municipal Power - Ohio	Chris Norton	Affirmative	
4	Consumers Energy Co.	David Frank Ronk	Affirmative	
4	Florida Municipal Power Agency	William S. May	Affirmative	
4	LaGen	Richard Comeaux		
4	Municipal Electric Utilities Association of New York	Timothy R. Bush		
4	Municipal Energy Agency of Nebraska	John Krajewski	Affirmative	
4	Northern California Power Agency	Fred E. Young		
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 2 of Grant County	Kevin J. Conway	Negative	View
4	Reedy Creek Improvement District	Doug Wagner	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	South Mississippi Electric Power Association	Dan Kay	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Alabama Electric Coop. Inc.	Tim Hattaway	Affirmative	
5	American National Power, Inc.	Dorothy Capra	Abstain	
5	APGI - Yadkin Division	Alan D. Jones	Abstain	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Power	Pamela Pahl		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale		
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Conectiv Energy Supply, Inc.	Richard K Douglass	Affirmative	
5	Constellation Generation Group	Michael F. Gildea	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Energy	Harold W. Adams	Affirmative	
5	East Kentucky Power Coop.	Gerard Bordes	Affirmative	

5	Entergy Operations, Inc.	Thomas Barnett	Affirmative	
5	Florida Municipal Power Agency	Steve McElhaney		
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Gainesville Regional Utilities	Mark L. Bennett		
5	JEA	Donald Gilbert	Abstain	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	PSEG Power LLC	Thomas Piascik		
5	Reedy Creek Energy Services	Bernie Budnik		
5	Salt River Project	Glen Reeves	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones		
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern Company Services, Inc.	Roger Green		
5	Tampa Electric Co.	Bill Smotherman	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	TXU Generation Company LP	Rickey Terrill	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Stephen J. Beuning	Affirmative	
6	AEP Service Corp.	Dana E. Horton	Affirmative	
6	Black Hills Power	Larry Williamson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Dominion Energy Marketing	Lou Oberski	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	Exelon Power Team	Pulin Shah		
6	FirstEnergy Solutions	Edward C. Stein	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Abstain	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	PP&L, Inc.	Thomas Hyzinski	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt Hammond	Affirmative	
6	Southern Company Generation and Energy Marketing	J. Roman Carter	Affirmative	
6	Split Rock Energy LLC	Donna Stephenson	Affirmative	
6	Tampa Electric Co.	Jose Benjamin Quintas	Affirmative	
6	Tenaska Power Services Co.	Ann Scott	Abstain	
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Eastman Chemical Company	Lloyd Webb	Affirmative	
7	Praxair Inc.	David Meade	Affirmative	
7	Steel Manufacturers Association	James Brew	Affirmative	
8	Energy Mark, Inc.	Howard F. Illian	Negative	View

8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Missouri Office of Public Counsel	Ryan Kind	Affirmative	
8	North Carolina Utilities Commission Public Staff	Jack Floyd	Affirmative	
8	Other	Michehl R. Gent	Affirmative	
8	Pennsylvania Office of Consumer Advocate	Sonny Popowsky	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Massachusetts Department of Telecommunications and Energy	Donald E. Nelson	Affirmative	
9	Minnesota Public Utilities Commission	Ken Wolf	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher	Affirmative	
9	North Carolina Utilities Commission	Sam Watson	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Sam R. Jones	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	ReliabilityFirst Corporation	Timothy R. Gallagher	Affirmative	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren		

609.452.8060 (Voice) - 609.452.9550 (Fax)
116-390 Village Boulevard, Princeton, New Jersey 08540-5721

Maureen E. Long
Standards Process Manager

April 17, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: One Initial Ballot Window and Three Recirculation Ballot Windows Open on April 17, 2007

The Standards Committee (SC) announces the following standards actions:

Initial Ballot Window Open April 17–26, 2007

Interpretation of VAR-002-1 Requirements 1 and 2

The initial ballot on the Interpretation of VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules, Requirements 1 and 2 will be conducted from 8 a.m. (EDT) on Tuesday, April 17 through 8 p.m. (EDT) Thursday, April 26, 2007.

This interpretation clarifies the intent of the use of the phrase, "operation in the automatic voltage control mode" in Requirements 1 and 2.

Three Recirculation Ballot Windows Open April 17–26, 2007

Each of the following three recirculation ballots will be conducted from 8 a.m. (EDT) on Tuesday, April 17 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the associated ballot pools are encouraged to review the comments submitted with the initial ballots, and the associated drafting team's responses to those comments.

Members of the ballot pools may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

In the recirculation ballot, votes are counted by exception only — if members don't indicate a revision to their original votes, the vote remains the same as in the first ballot.

Balance Resources and Demand Standards

The recirculation ballot for the following set of Balance Resources and Demand standards will be conducted from 8 a.m. (EDT) on Tuesday, April 17 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the ballot pool are encouraged to review the comments submitted with the initial ballot, and the drafting team's responses to those comments.

BAL-007-1 — Balance of Resources and Demand
BAL-008-1 — Frequency and Area Control Error
BAL-009-1 — Actions to Return Frequency to within Frequency Trigger Limits
BAL-010-1 — Frequency Bias Settings
BAL-011-1 — Frequency Limits

These standards require entities to maintain interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e., normal and abnormal), to prevent unwarranted load shedding and to prevent frequency-related cascading collapse of the interconnected grid. The ballot for the above set of standards also includes the Balance Resources and Demand Implementation Plan.

Nuclear Plant Interface Coordination Standard (NUC-001)

The recirculation ballot for the Nuclear Plant Interface Coordination (NUC-001-1) standard will be conducted from 8 a.m. (EDT) on Tuesday, April 17, 2007 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the ballot pool are encouraged to review the comments submitted with the initial ballot, and the drafting team's responses to those comments.

This standard requires coordination between nuclear plant generator operators and transmission entities to ensure safe operation and shutdown of nuclear plants. The ballot for this standard also includes the Nuclear Plant Interface Coordination Implementation Plan.

Interpretation of BAL-005 — Automatic Generation Control Requirement 17

The recirculation ballot for the Interpretation of BAL-005-0 — Automatic Generation Control Requirement 17 will be conducted from 8 a.m. (EDT) on Tuesday, April 17, 2007 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the ballot pool are encouraged to review the comments submitted with the initial ballot, and the drafting team's responses to those comments.

The interpretation clarifies that the Balancing Authority is required to check and calibrate its control room time error and frequency devices against a common reference at least annually, but the requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Ballot Results	
Ballot Name:	Interpretation Request for BAL-005_rc
Ballot Period:	4/17/2007 - 4/26/2007
Ballot Type:	recirculation
Total # Votes:	221
Total Ballot Pool:	235
Quorum:	**94.04 % The Quorum has been reached**
Weighted Segment Vote:	96.66 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	70	1	61	0.968	2	0.032	3	4
2 - Segment 2.	10	0.9	9	0.9	0	0	0	1
3 - Segment 3.	52	1	42	0.955	2	0.045	4	4
4 - Segment 4.	16	1	13	0.929	1	0.071	0	2
5 - Segment 5.	39	1	33	0.971	1	0.029	3	2
6 - Segment 6.	24	1	21	1	0	0	2	1
7 - Segment 7.	3	0.3	3	0.3	0	0	0	0
8 - Segment 8.	6	0.6	5	0.5	1	0.1	0	0
9 - Segment 9.	7	0.7	7	0.7	0	0	0	0
10 - Segment 10.	8	0.8	8	0.8	0	0	0	0
Totals	**235**	**8.3**	**202**	**8.023**	**7**	**0.277**	**12**	**14**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	AEP Service Corp. -- Transmission System AEP	Scott P. Moore	Affirmative	
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Alliant Energy	Kenneth Goldsmith	Affirmative	
1	Ameren Services Company	Peggy Ladd	Affirmative	
1	American Public Power Association	E. Nick Henery	Affirmative	
1	American Transmission Company, LLC	Douglas F. Johnson	Affirmative	View
1	Avista Corp.	Scott Kinney	Affirmative	
1	Baltimore Gas & Electric Company	John J. Moraski	Affirmative	View
1	Basin Electric Power Cooperative	Mike Risan	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	

1	Central Maine Power Company	David Mark Conroy	Abstain	
1	Consolidated Edison Co. of New York	Edwin E. Thompson PE	Affirmative	
1	Dominion Virginia Power	William L. Thompson		
1	Duke Energy	Doug Hils	Affirmative	
1	Duquesne Light Co.	Bob McClelland	Abstain	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Brian F. Thumm	Affirmative	
1	JEA	Ted E. Hobson	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Keyspan LIPA	Richard J. Bolbrock	Negative	
1	LG&E Energy Transmission Services	Bradley Young	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Manitoba Hydro	Robert G. Coish	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	National Grid USA	Herbert Schrayshuen	Affirmative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Negative	
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Nova Scotia Power Inc.	David D. Little	Affirmative	View
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Melvin H. Perkins	Affirmative	
1	Oncor	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Verne B. Ingersoll	Affirmative	
1	Public Service Company of New Mexico	Keith Nix	Abstain	
1	Public Service Electric and Gas Co.	Colin Loxley	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown		
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Affirmative	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	South Carolina Electric & Gas Co.	Lee N. Xanthakos	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	

1	Southwest Transmission Coop., Inc.	Alan H. Wilkinson	Affirmative	
1	Southwestern Power Administration	Stanley Mason	Affirmative	
1	Tampa Electric Co.	Paul Michael Davis	Affirmative	
1	Tennessee Valley Authority	Larry G. Akens	Affirmative	
1	Tri-State G & T Association Inc.	Bruce A Sembrick		
1	Westar Energy	Allen Klassen	Affirmative	View
1	Western Area Power Administration - CM WACM	Mark E. Fidrych	Affirmative	
1	Western Farmers Electric Coop.	Alan Derichsweiler	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Independent Electricity System Operator	Don Tench	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Rocky Mountain-Desert Southwest Reliability Center	Frank R. McElvain		
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Negative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Tallahassee	Rusty S. Foster	Abstain	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Abstain	
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy Co.	David A. Lapinski	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander	Affirmative	
3	Florida Power & Light Co.	W.R. Schoneck	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Gulf Power Company	William F. Pope	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	Manitoba Hydro	Ronald Dacombe	Affirmative	
3	MAPPCOR	Peter Koegel		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	View

3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	View
3	Oklahoma Gas and Electric Co.	Gary Clear	Abstain	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Reliant Energy Services	John Meyer	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	SaskPower	Jeff Gienow	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron	Affirmative	
3	Tri-State G & T Association Inc.	Dillwyn H. Ramsay		
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alabama Electric Coop. Inc.	Kenneth Skroback	Affirmative	
4	American Municipal Power - Ohio	Chris Norton	Affirmative	
4	Consumers Energy Co.	David Frank Ronk	Affirmative	
4	Florida Municipal Power Agency	William S. May	Affirmative	
4	LaGen	Richard Comeaux		
4	Municipal Electric Utilities Association of New York	Timothy R. Bush		
4	Municipal Energy Agency of Nebraska	John Krajewski	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 2 of Grant County	Kevin J. Conway	Negative	View
4	Reedy Creek Improvement District	Doug Wagner	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	South Mississippi Electric Power Association	Dan M Kay	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Alabama Electric Coop. Inc.	Tim Hattaway	Affirmative	
5	American National Power, Inc.	Dorothy Capra	Abstain	
5	APGI - Yadkin Division	Alan Jones	Abstain	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Power	Pamela Pahl	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Conectiv Energy Supply, Inc.	Richard K Douglass	Affirmative	
5	Constellation Generation Group	Michael F. Gildea	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	

5	Dominion Energy	Harold W. Adams	Affirmative	
5	East Kentucky Power Coop.	Gerard Bordes	Affirmative	
5	Entergy Operations, Inc.	Thomas Barnett	Affirmative	
5	Florida Municipal Power Agency	Steve McElhaney		
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Gainesville Regional Utilities	Mark L. Bennett		
5	JEA	Donald Gilbert	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	PSEG Power LLC	Thomas Piascik	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern Company Services, Inc.	Roger Green	Affirmative	
5	Tampa Electric Co.	Bill Smotherman	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	TXU Generation Company LP	Rickey Terrill	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Stephen J. Beuning	Affirmative	
6	AEP Service Corp.	Dana E. Horton	Affirmative	
6	Black Hills Power	Larry Williamson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Dominion Energy Marketing	Lou Oberski	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	Exelon Power Team	Pulin Shah		
6	FirstEnergy Solutions	Edward C. Stein	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
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6	Manitoba Hydro	Daniel Prowse	Affirmative	
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6	South Carolina Electric & Gas Co.	Matt Hammond	Affirmative	
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6	Tenaska Power Services Co.	Ann Scott	Abstain	
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8	Energy Mark, Inc.	Howard F. Illian	Negative	View

8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Missouri Office of Public Counsel	Ryan Kind	Affirmative	
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8	Pennsylvania Office of Consumer Advocate	Sonny Popowsky	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Minnesota Public Utilities Commission	Ken Wolf	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher	Affirmative	
9	North Carolina Utilities Commission	Sam Watson	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
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10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	ReliabilityFirst Corporation	Timothy R. Gallagher	Affirmative	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

609.452.8060 (Voice) - 609.452.9550 (Fax)
116-390 Village Boulevard, Princeton, New Jersey 08540-5721

A. Introduction

1. **Title:** **Automatic Generation Control**

2. **Number:** BAL-005-1

3. **Purpose:**

   This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

   4.1. Balancing Authorities.

   4.2. Generator Operators.

   4.3. Transmission Operators.

   4.4. Load Serving Entities.

5. **Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Time Frame

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None.

F. Associated Documents

Interpretation to BAL-005-1 Requirement 17.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	May 2, 2007	Approved by BOT	Revised

Interpretation of BAL-005-1 Requirement 17

BAL-005-0, Requirement 17 requires that the Balancing Authority to check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to "annually check and calibrate" the devices listed in the table, unless they are included in the control center time error and frequency devices.

Exhibit C-1

Interpretation of Reliability Standard VAR-002-1, Requirements R1 and R2 Proposed for Approval

Request for Interpretation of NERC Standard VAR-002-1

Dated January 24, 2007
John H. Stout
Mariner Consulting Services, Inc.
1303 Lake Way Drive
Taylor Lake Village, Texas 77586

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation of NERC Standard VAR-002-1
Prepared by Phase 3&4 Standard Drafting Team Members
Dated March 5, 2007

In response to February 2007 request from
John H. Stout
Mariner Consulting Services, Inc.
1303 Lake Way Drive
Taylor Lake Village, Texas 77586

Questions and Answers

The answers to the two questions posed by Mr. John H. Stout are:

1. Question: First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Answer: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Question: Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Answer: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

Background and Discussion

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R1 clearly states controlling voltage. This can only be accomplished by using the automatic voltage control mode. Using the Power Factor (PF) or constant MVAR control is not a true method to control voltage even though they may have some effect on voltage. This is the baseline mode of operation that is clearly conditioned by “unless the Generator Operator has notified the Transmission Operator”. The following Requirement R2 introduces the possibility of an exemption to this baseline mode of operation discussed below.

The above interpretation is further reinforced by reviewing the origin of the requirement. The current Requirement R1 is an evolution of the words in the associated source document, namely NERC Planning Standards Compliance Template for III.C.M1, “Operation of all synchronous generators in the automatic voltage control mode”.

As stated in the original III.C.S1 Standard:

“All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved otherwise by the transmission system operator.”

Requirement R2 of Standard VAR-002-1 goes on to state that “Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.” The purpose of this requirement is to give the Transmission Operator the ability to direct the Generator Operator to use another mode of operation. This ability may be necessary based on the Transmission Operator’s system studies and/or knowledge of system conditions. This ability also gives the Transmission Operator the latitude to work with the Generator Operator who has a generating unit that lacks the physical equipment to be able to run in the automatic voltage control mode or has contractual requirements to operate in a certain manner.

Both Requirements R1 and R2 in VAR-002-1 were worded such that they coordinate with Requirement R4 in VAR-001-1:

“Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage). “

Again this Requirement R4 reflects that the baseline mode of operation is to use the automatic voltage control mode with the option for the Transmission Operator to specify other modes of operation as dictated by system studies and needs to maintain system reliability.

Exhibit C-2

Reliability Standard VAR-002-1a

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**

2. **Number:** VAR-002-1

3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.

4. **Applicability**

   4.1. Generator Operator.

   4.2. Generator Owner.

5. **Effective Date:** Immediately after approval of applicable regulatory authorities

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

R4.1.1. Tap settings.

---

[1] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

R4.1.2. Available fixed tap ranges.

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One incident of failing to notify the Transmission Operator as identified in , R3.1, R3.2 or R5.1.

2.1.2 One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1,R3.2 or R5.1.

2.2.2 More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.3.2 More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 Failed to comply with the Transmission Operator’s directives as identified in R2.

2.4.2 Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.4.3 Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

3.1.1 **Level One:** Not applicable.

3.1.2 **Level Two:** Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.

3.1.3 **Level Three:** No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage

3.1.4 **Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

E. Regional Differences

None identified.

F. Associated Documents

Appendix 1 – Interpretation of Requirements R1 and R2.

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	

Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-1
3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.
4. **Applicability**
   - **4.1.** Generator Operator.
   - **4.2.** Generator Owner.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities

Deleted: Six months after effective date of VAR-001-1.

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

R4.1.1. Tap settings.

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Deleted: Effective Date: Six months after effective date of VAR-001-1.

[1] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

R4.1.2. Available fixed tap ranges.

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

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The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One incident of failing to notify the Transmission Operator as identified in , R3.1, R3.2 or R5.1.

2.1.2 One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1,R3.2 or R5.1.

2.2.2 More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.3.2 More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 Failed to comply with the Transmission Operator's directives as identified in R2.

2.4.2 Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.4.3 Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

3.1.1 **Level One:** Not applicable.

3.1.2 **Level Two:** Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.

3.1.3 **Level Three:** No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage

3.1.4 **Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

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Deleted: Effective Date: Six months after effective date of VAR-001-1.

E. Regional Differences

None identified.

F. Associated Documents

Appendix 1 – Interpretation of Requirements R1 and R2.

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
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Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

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Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

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Deleted: 2006
Deleted: Effective Date: Six months after effective date of VAR-001-1.

Exhibit C-3

Record of Development of Formal Interpretations for VAR-002-1, Requirements R1 and R2

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Interpretation - VAR-002 - Generator Operation for Maintaining Network Voltage Schedules

Registered Ballot Body | Reliability Standards Home Page

Status
The interpretation for standard VAR-002-1, Requirements 1 and 2 was approved by stakeholders and is pending regulatory filing.

Purpose / Industry Need
Mariner Consulting Services, Inc., requested a formal interpretation to VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules, Requirements 1 and 2. Members of the Phase III–IV Standards Drafting Team, working with NERC staff, developed the interpretation.

Proposed Standard	Supporting Documents	Comment Period	Comments Received	Response to Comments
Announcement (6) Request for Interpretation VAR-002-1, Requirements 1 and 2 - Generator Operation for Maintaining Network Voltage Schedules Posted for 10-day Recirculation Ballot Window June 20 through June 29, 2007 VAR-002-1 Interpretation (Same as 1)		06/30/07 - 06/29/07 10-day Recirculation Ballot Window (closed)		Ballot Results (7)
Announcement Request for Interpretation VAR-002-1, Requirements 1 and 2 - Generator Operation for Maintaining Network Voltage Schedules		04/17/07 - 04/26/07 10-day Initial Ballot Window Closed		Ballot Results (4) Consideration of Comments (5)

Posted for 10-day Initial Ballot Window April 17 through April 26, 2007 VAR-002-1 Interpretation (Same as 1)				
Announcement (3) Request for Interpretation VAR-002-1, Requirements 1 and 2 - Generator Operation for Maintaining Network Voltage Schedules Posted for 30-day Pre-ballot Review March 15 through April 13, 2007 VAR-002-1 Interpretation (1)	Mariner Consulting Services, Inc. Request for Interpretation (2) VAR-002-1, Requirements 1 and 2	03/15/07 - 04/16/06 30-day Pre-ballot Review		

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All comments should be forwarded to sarcomm@nerc.net.
Questions? Contact Barbara Bogenrief - barbara.bogenrief@nerc.net or 609-452-8060.

Request for Interpretation of NERC Standard VAR-002-1

Dated January 24, 2007
John H. Stout
Mariner Consulting Services, Inc.
1303 Lake Way Drive
Taylor Lake Village, Texas 77586

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation of NERC Standard VAR-002-1
Prepared by Phase 3&4 Standard Drafting Team Members
Dated March 5, 2007

In response to February 2007 request from
John H. Stout
Mariner Consulting Services, Inc.
1303 Lake Way Drive
Taylor Lake Village, Texas 77586

Questions and Answers

The answers to the two questions posed by Mr. John H. Stout are:

1. Question: First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Answer: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Question: Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Answer: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

Background and Discussion

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R1 clearly states controlling voltage. This can only be accomplished by using the automatic voltage control mode. Using the Power Factor (PF) or constant MVAR control is not a true method to control voltage even though they may have some effect on voltage. This is the baseline mode of operation that is clearly conditioned by “unless the Generator Operator has notified the Transmission Operator”. The following Requirement R2 introduces the possibility of an exemption to this baseline mode of operation discussed below.

The above interpretation is further reinforced by reviewing the origin of the requirement. The current Requirement R1 is an evolution of the words in the associated source document, namely NERC Planning Standards Compliance Template for III.C.M1, “Operation of all synchronous generators in the automatic voltage control mode”.

As stated in the original III.C.S1 Standard:

“All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved otherwise by the transmission system operator.”

Requirement R2 of Standard VAR-002-1 goes on to state that “Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.” The purpose of this requirement is to give the Transmission Operator the ability to direct the Generator Operator to use another mode of operation. This ability may be necessary based on the Transmission Operator’s system studies and/or knowledge of system conditions. This ability also gives the Transmission Operator the latitude to work with the Generator Operator who has a generating unit that lacks the physical equipment to be able to run in the automatic voltage control mode or has contractual requirements to operate in a certain manner.

Both Requirements R1 and R2 in VAR-002-1 were worded such that they coordinate with Requirement R4 in VAR-001-1:

“Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage). “

Again this Requirement R4 reflects that the baseline mode of operation is to use the automatic voltage control mode with the option for the Transmission Operator to specify other modes of operation as dictated by system studies and needs to maintain system reliability.

Mariner Consulting Services, Inc.

John H. Stout mariner@houston.rr.com 1303 Lake Way Drive Taylor Lake Village, Texas 77586 713-252-0535

January 24, 2007

Maureen E. Long
Standards Process Manager
North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, New Jersey 08540-5721

Request for Interpretation of NERC Standard VAR-002-1

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage or Reactive Power output as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows…

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Please let me know if any additional information is needed in order to provide the requested interpretation.

Thank you for addressing this request,

John Stout

John Stout

Maureen E. Long
Standards Process Manager

March 15, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement:
Pre-ballot Window and Ballot Pool Open on March 15, 2007

The Standards Committee announces the following standards actions:

Pre-ballot Window and Ballot Pool Open on March 15, 2007 for Interpretation of VAR-002-1, Requirements 1 and 2

Mariner Consulting Services, Inc., requested a formal interpretation to VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules, Requirements 1 and 2. Members of the Phase III–IV Standards Drafting Team, working with NERC staff, developed the interpretation.

VAR-002-1, Requirements 1 and 2 states:

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

Two specific questions need to be answered.

- *First, does AVR operation in the constant PF or constant Mvar modes comply with R1?* Answer: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

- *Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?*

[1] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

> Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

In accordance with the *Reliability Standards Development Procedure*, the interpretation must be posted for a 30-day, pre-ballot review, and then balloted. There is no public comment period for an interpretation. Balloting will be conducted following the same method used for balloting standards. If the interpretation is approved by its ballot pool, then the interpretation will be appended to the standard and will become effective when adopted by the NERC Board of Trustees and approved by the applicable regulatory authorities. The interpretation will remain appended to the standard until the standard is revised through the normal standards development process. When the standard is revised, the clarifications provided by the interpretation will be incorporated into the revised standard.

The Interpretation of VAR-002-1, Requirements 1 and 2 is posted for a 30-day, pre-ballot review. A ballot pool to vote on the interpretation has been formed and will remain open through 8 a.m. (EDT) Friday, April 16, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server[2]." The list server for this ballot pool is called: bp-interpret_var-002-1_in@nerc.com

Before joining the ballot pool, please make sure that you will be available during the ballot window to cast your ballot. The initial ballot for the interpretation to VAR-002-1 will be conducted from 8 a.m. (EDT) on Friday, April 16 through 8 p.m. (EDT) Monday, April 26, 2006.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

[2] For assistance in using a list server, contact Barbara Bogenrief at 609-452-8060.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Ballot Results	
Ballot Name:	Interpretation Request for Standard VAR-002-1_in
Ballot Period:	4/17/2007 - 4/26/2007
Ballot Type:	Initial
Total # Votes:	187
Total Ballot Pool:	224
Quorum:	**83.48 % The Quorum has been reached**
Weighted Segment Vote:	97.23 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	67	1	53	0.964	2	0.036	0	12
2 - Segment 2.	9	0.7	7	0.7	0	0	0	2
3 - Segment 3.	53	1	41	0.953	2	0.047	1	9
4 - Segment 4.	10	0.9	9	0.9	0	0	0	1
5 - Segment 5.	43	1	32	0.889	4	0.111	0	7
6 - Segment 6.	25	1	21	1	0	0	1	3
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	4	0.4	4	0.4	0	0	0	0
9 - Segment 9.	5	0.5	5	0.5	0	0	0	0
10 - Segment 10.	8	0.5	5	0.5	0	0	0	3
Totals	**224**	**7**	**177**	**6.806**	**8**	**0.194**	**2**	**37**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	AEP Service Corp. -- Transmission System AEP	Scott P. Moore	Affirmative	
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Alliant Energy	Kenneth Goldsmith	Affirmative	
1	AltaLink Management Ltd.	Rick Spyker	Affirmative	
1	Ameren Services Company	Kirit S Shah	Affirmative	
1	American Public Power Association	E. Nick Henery	Affirmative	
1	Avista Corp.	Scott Kinney	Affirmative	
1	Baltimore Gas & Electric Company	John J. Moraski	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	Central Maine Power Company	David Mark Conroy		

1	Consolidated Edison Co. of New York	Edwin E. Thompson PE	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson		
1	Duke Energy	Doug Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Julien Gagnon	Affirmative	
1	ITC Transmission	Brian F. Thumm		
1	JEA	Ted E. Hobson	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger		
1	Keyspan LIPA	Richard J. Bolbrock	Affirmative	
1	Manitoba Hydro	Robert G. Coish	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Montana-Dakota Utilities Co.	Henry Ford		
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	National Grid USA	Herbert Schrayshuen	Affirmative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano		
1	Northeast Utilities	David H Boguslawski		
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Melvin H. Perkins		
1	Oncor	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	PacifiCorp	Robert Williams		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Verne B. Ingersoll	Affirmative	
1	Public Service Company of New Mexico	Keith Nix	Affirmative	
1	Public Service Electric and Gas Co.	Colin Loxley	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Negative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Affirmative	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Coop., Inc.	Alan H. Wilkinson	Affirmative	
1	Southwestern Power Administration	Stanley Mason	Affirmative	
1	Tampa Electric Co.	Paul Michael Davis		

1	Tri-State G & T Association Inc.	Bruce A Sembrick		
1	Tucson Electric Power Co.	Ronald P. Belval	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration - CM WACM	Mark E. Fidrych	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park		
2	California ISO	David Hawkins	Affirmative	
2	Independent Electricity System Operator	Don Tench	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	Basin Electric Power Cooperative	Daniel Klempel	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow		
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Negative	View
3	Consumers Energy Co.	David A. Lapinski	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik		
3	Duke Energy	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander		
3	Florida Power & Light Co.	W.R. Schoneck	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	William F. Pope	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	Manitoba Hydro	Ronald Dacombe	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Don Horsley	Affirmative	
3	National Rural Electric Cooperative Association	Patricia Metro		
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Oklahoma Gas and Electric Co.	Gary Clear	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	

3	PECO Energy an Exelon Co.	John J McCawley	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Reliant Energy Services	John Meyer	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson	Negative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	SaskPower	Jeff Gienow	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Cynthia Herron	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alabama Electric Coop. Inc.	Kenneth Skroback	Affirmative	
4	American Municipal Power - Ohio	Chris Norton		
4	Consumers Energy Co.	David Frank Ronk	Affirmative	
4	Florida Municipal Power Agency	William S. May	Affirmative	
4	Oklahoma Municipal Power Authority	Robin J. Morecroft	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 2 of Grant County	Kevin J. Conway	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Alabama Electric Coop. Inc.	Tim Hattaway	Affirmative	
5	Allegheny Energy Supply Company, LLC	Carol Krysevig	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Power	Pamela Pahl	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Calpine Corporation	John Brent Hebert		
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Conectiv Energy Supply, Inc.	Richard K Douglass	Affirmative	
5	Constellation Generation Group	Michael F. Gildea	Negative	View
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dynegy	Greg A. Mason		
5	East Kentucky Power Coop.	Gerard Bordes	Affirmative	
5	Entegra Power Group, LLC	Kenneth Parker	Negative	
5	Exelon Corporation	Jack Crowley	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	Douglas Keegan		
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Gainesville Regional Utilities	Mark L. Bennett	Negative	
5	Great River Energy	Nathan Domyahn	Affirmative	
5	JEA	Donald Gilbert	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	

5	Oklahoma Gas and Electric Co.	Kim Morphis	Affirmative	
5	Pacific Gas and Electric Company	Richard Padilla		
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Thomas Piascik	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	Reliant Energy Services	Thomas Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern Company Services, Inc.	Roger Green	Affirmative	
5	Tampa Electric Co.	Bill Smotherman	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	Mark Bowman	Negative	View
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Stephen J. Beuning		
6	AEP Service Corp.	Dana E. Horton	Affirmative	
6	Black Hills Power	Larry Williamson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Rebecca Adrienne Craft		
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Dominion Energy Marketing	Lou Oberski	Affirmative	
6	Duke Energy	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Edward C. Stein		
6	Florida Municipal Power Agency	Robert C. Williams		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	Missouri River Energy Services	Gerald A. Tielke	Affirmative	
6	PP&L, Inc.	Thomas Hyzinski	Abstain	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt Hammond	Affirmative	
6	Southern Company Generation and Energy Marketing	J. Roman Carter	Affirmative	
6	Tampa Electric Co.	Jose Benjamin Quintas	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Missouri Office of Public Counsel	Ryan Kind	Affirmative	
8	North Carolina Utilities Commission Public Staff	Jack Floyd	Affirmative	
8	Other	Michehl R. Gent	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	View
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
	New York State Public Service			

9	Commission	James T. Gallagher	Affirmative	
9	North Carolina Utilities Commission	Sam Watson	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Sam R. Jones	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Larry Brusseau	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt		
10	ReliabilityFirst Corporation	Timothy R. Gallagher		
10	SERC Reliability Corporation	Gerry W Cauley	Affirmative	View
10	Southwest Power Pool	Charles H. Yeung	Affirmative	

609.452.8060 (Voice) - 609.452.9550 (Fax)
116-390 Village Boulevard, Princeton, New Jersey 08540-5721

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot of Interpretation of VAR-002-1 Requirements 1 and 2

Summary Consideration: While commenters made suggestions to improve the overall wording of the interpretation, most stakeholders agreed with the interpretation and the drafting team did not make any modifications to the interpretation. There is a project in Reliability Standards Development Plan 2007-2009 that includes the revision of VAR-002-1. The suggestions for improvements to the language of the interpretation can be used when the requirements in VAR-002-1 are revised.

Organization:	Baltimore Gas & Electric Company
Member:	John J. Moraski
Comment:	NERC needs to be more specific in their definition of Automatic Operation. Some generators may have non-standard AVR configurations or other operating limitations that require them to operate in a specific mode that NERC may not recognize as "Automatic" (since automatic can mean different things)
Response: Requirement R4 of Standard VAR-002-1 states "Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings1) as directed by the Transmission Operator." The purpose of this requirement is to give the Transmission Operator the ability to direct the Generator Operator to use another mode of automatic control. This also gives the Transmission Operator the latitude to work with the Generator Operator who has a generating unit that lacks the voltage control mode for automatic operation.	
Organization:	Constellation Energy
Member:	Carolyn Ingersoll
Comment:	In response to question 1 [does AVR operation in the constant PF or constant Mvar modes comply with VAR-002-1, R1?] the interpretation state that only operation in constant voltage mode meets this requirement. The problem with the interpretation is that as indicated, the "answer is predicated on the assumption that the generator has the physical equipment that will allow such operation." The interpretation needs to clarify what is the appropriate mode of operation, which meets the VAR-002-1, R1, if this assumption is incorrect and the generator does not have the physical equipment that will allow such operation.
Response: Requirement R4 of Standard VAR-002-1 states "Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator." The purpose of this requirement is to give the Transmission Operator the ability to direct the Generator Operator to use another mode of automatic control. This also gives the Transmission Operator the latitude to work with the Generator Operator who has a generating unit that lacks the voltage control mode for automatic operation.	
Organization:	Constellation Generation Group
Member:	Michael F. Gildea
Comment:	NERC's Interpretation is not possible for all our generation.
Response: This comment does not provide a specific reason why the interpretation is not possible.	

Organization:	Tennessee Valley Authority
Member:	Mark Bowman
Comment:	The interpretation of question 1 is misleading since it uses the term "No", but in fact means "Maybe". The answer given equates to "No, except when it's allowed". This is equivalent to "sometimes", which is legally equivalent to "Yes", when considering how this will be enforced. A more appropriate answer would be "Yes, but you must always follow both requirements R1 and R2". So being in auto MVAR Control mode is allowed if the Transmission Operator has directed this.
Response: Although the wording of the interpretation could be improved, most entities agreed with the interpretation as presented and there is no consensus to modify the interpretation. Improvements to the wording of the requirements can be made when VAR-002 is modified as part of the Reliability Standards Development Plan 2007-2009.	
Organization:	California Energy Commission
Member:	William Mitchell Chamberlain
Comment:	The interpretation improves the standard by clarifying that generators may not unilaterally decide not to operate their AVRs in constant voltage mode by simply notifying their transmission operator. It still leaves to the discretion of transmission operators and generators the extent to which an entire Interconnection will be protected from voltage transients by having nearly all of the AVRs in this mode. WECC has a more protective standard that requires generators with AVR to operate in constant voltage mode with very limited exceptions that are clearly defined.
Response: Adopting the more restrictive language used within WECC may be appropriate when this standard is reviewed as part of the Reliability Standards Development Plan 2007-2009.	
Organization:	SERC Reliability Corporation
Member:	Gerry W Cauley
Comment:	Although agreeing with the intent of this interpretation, the response to Q1 may be confusing because of conflicting statements. The first statement "No, only operation in constant voltage mode meets this requirement." is stated in absolute terms, which contracticts the allowance for an exception that "the Transmission Operator has not directed the generator to run in a mode other than constant voltage." Suggest the statements be combined as: "No, the Generator Operator is required to operate in constant voltage mode unless the Transmission Operator has directed the generator to operate in another mode."
Response: Although the wording of the interpretation could be improved, most entities agreed with the interpretation as presented and there is no consensus to modify the interpretation. Improvements to the wording of the requirements can be made when VAR-002 is modified as part of the Reliability Standards Development Plan 2007-2009.	

Maureen E. Long
Standards Process Manager

April 17, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: One Initial Ballot Window and Three Recirculation Ballot Windows Open on April 17, 2007

The Standards Committee (SC) announces the following standards actions:

Initial Ballot Window Open April 17–26, 2007

Interpretation of VAR-002-1 Requirements 1 and 2

The initial ballot on the Interpretation of VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules, Requirements 1 and 2 will be conducted from 8 a.m. (EDT) on Tuesday, April 17 through 8 p.m. (EDT) Thursday, April 26, 2007.

This interpretation clarifies the intent of the use of the phrase, "operation in the automatic voltage control mode" in Requirements 1 and 2.

Three Recirculation Ballot Windows Open April 17–26, 2007

Each of the following three recirculation ballots will be conducted from 8 a.m. (EDT) on Tuesday, April 17 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the associated ballot pools are encouraged to review the comments submitted with the initial ballots, and the associated drafting team's responses to those comments.

Members of the ballot pools may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

In the recirculation ballot, votes are counted by exception only — if members don't indicate a revision to their original votes, the vote remains the same as in the first ballot.

Balance Resources and Demand Standards

The recirculation ballot for the following set of Balance Resources and Demand standards will be conducted from 8 a.m. (EDT) on Tuesday, April 17 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the ballot pool are encouraged to review the comments submitted with the initial ballot, and the drafting team's responses to those comments.

BAL-007-1 — Balance of Resources and Demand
BAL-008-1 — Frequency and Area Control Error
BAL-009-1 — Actions to Return Frequency to within Frequency Trigger Limits
BAL-010-1 — Frequency Bias Settings
BAL-011-1 — Frequency Limits

These standards require entities to maintain interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e., normal and abnormal), to prevent unwarranted load shedding and to prevent frequency-related cascading collapse of the interconnected grid. The ballot for the above set of standards also includes the Balance Resources and Demand Implementation Plan.

Nuclear Plant Interface Coordination Standard (NUC-001)

The recirculation ballot for the Nuclear Plant Interface Coordination (NUC-001-1) standard will be conducted from 8 a.m. (EDT) on Tuesday, April 17, 2007 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the ballot pool are encouraged to review the comments submitted with the initial ballot, and the drafting team's responses to those comments.

This standard requires coordination between nuclear plant generator operators and transmission entities to ensure safe operation and shutdown of nuclear plants. The ballot for this standard also includes the Nuclear Plant Interface Coordination Implementation Plan.

Interpretation of BAL-005 — Automatic Generation Control Requirement 17

The recirculation ballot for the Interpretation of BAL-005-0 — Automatic Generation Control Requirement 17 will be conducted from 8 a.m. (EDT) on Tuesday, April 17, 2007 through 8 p.m. (EDT) Thursday, April 26, 2007. All members of the ballot pool are encouraged to review the comments submitted with the initial ballot, and the drafting team's responses to those comments.

The interpretation clarifies that the Balancing Authority is required to check and calibrate its control room time error and frequency devices against a common reference at least annually, but the requirement to "annually check and calibrate" does not address any devices outside of the operations control room.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Approved by Stakeholders: June 29, 2007

Request for Interpretation of NERC Standard VAR-002-1

Dated January 24, 2007
John H. Stout
Mariner Consulting Services, Inc.
1303 Lake Way Drive
Taylor Lake Village, Texas 77586

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation of NERC Standard VAR-002-1
Prepared by Phase 3&4 Standard Drafting Team Members
Dated March 5, 2007

In response to February 2007 request from
John H. Stout
Mariner Consulting Services, Inc.
1303 Lake Way Drive
Taylor Lake Village, Texas 77586

Questions and Answers

The answers to the two questions posed by Mr. John H. Stout are:

1. Question: First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Answer: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Question: Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Answer: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

Background and Discussion

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R1 clearly states controlling voltage. This can only be accomplished by using the automatic voltage control mode. Using the Power Factor (PF) or constant MVAR control is not a true method to control voltage even though they may have some effect on voltage. This is the baseline mode of operation that is clearly conditioned by “unless the Generator Operator has notified the Transmission Operator”. The following Requirement R2 introduces the possibility of an exemption to this baseline mode of operation discussed below.

The above interpretation is further reinforced by reviewing the origin of the requirement. The current Requirement R1 is an evolution of the words in the associated source document, namely NERC Planning Standards Compliance Template for III.C.M1, “Operation of all synchronous generators in the automatic voltage control mode”.

As stated in the original III.C.S1 Standard:

“All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved otherwise by the transmission system operator.”

Requirement R2 of Standard VAR-002-1 goes on to state that “Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.” The purpose of this requirement is to give the Transmission Operator the ability to direct the Generator Operator to use another mode of operation. This ability may be necessary based on the Transmission Operator’s system studies and/or knowledge of system conditions. This ability also gives the Transmission Operator the latitude to work with the Generator Operator who has a generating unit that lacks the physical equipment to be able to run in the automatic voltage control mode or has contractual requirements to operate in a certain manner.

Both Requirements R1 and R2 in VAR-002-1 were worded such that they coordinate with Requirement R4 in VAR-001-1:

“Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage). “

Again this Requirement R4 reflects that the baseline mode of operation is to use the automatic voltage control mode with the option for the Transmission Operator to specify other modes of operation as dictated by system studies and needs to maintain system reliability.

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-1
3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.
4. **Applicability**
   - **4.1.** Generator Operator.
   - **4.2.** Generator Owner.
5. **Effective Date:** Six months after effective date of VAR-001-1.

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator..

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

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[1] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One incident of failing to notify the Transmission Operator as identified in , R3.1, R3.2 or R5.1.

2.1.2 One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1,R3.2 or R5.1.

2.2.2 More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.3.2 More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 Failed to comply with the Transmission Operator’s directives as identified in R2.

2.4.2 Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.4.3 Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

3.1.1 **Level One:** Not applicable.

3.1.2 **Level Two:** Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.

3.1.3 **Level Three:** No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage

3.1.4 **Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006