BEFORE THE
RÉGIE DE L'ÉNERGIE
THE PROVINCE OF QUÉBEC

NORTH AMERICAN ELECTRIC	**)**
RELIABILITY CORPORATION	**)**

NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FORMAL INTERPRETATIONS TO RELIABILITY STANDARDS

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC") hereby submits notice of interpretations to requirements of two Commission-approved NERC Reliability Standards:

- BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5 and R5.1
- VAR-001-1 — Voltage and Reactive Control, Requirement R4

No modifications to the language contained in these specific requirements are being proposed.

The NERC Board of Trustees approved the formal interpretation to: BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5 and R5.1 on February 12, 2008, and VAR-001-1 — Voltage and Reactive Control, Requirement R4 on March 26, 2008. Exhibits A-1 and B-1 to this filing set forth the formal interpretations. Exhibits A-2 and B-2 contain the affected Reliability Standards containing the appended interpretations. Exhibits A-3 and B-3 contain the complete development records of the formal interpretations to the Reliability Standard requirements.

NERC filed these formal interpretations with the Federal Energy Regulatory Commission ("FERC") on July 28, 2008, and is also filing these formal interpretations with the other applicable governmental authorities in Canada.

II. NOTICES AND COMMUNICATIONS

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

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III. BACKGROUND

a. Basis for Approval of Proposed Interpretations

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.

b. Reliability Standards Development Procedure

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 FERC and governmental authorities in Canada. 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 and B-1 have been developed and approved by industry stakeholders using NERC's *Reliability Standards Development*

Procedure; they have been approved by the NERC Board of Trustees as outlined in the Introduction section above.

IV. BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5 and R5.1

In Section IV(a), NERC explains the need for and development of the formal interpretations BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5 and R5.1. In addition, NERC demonstrates that the formal interpretation is consistent with the stated reliability goal of the Reliability Standard 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-003-0 — Frequency Response and Bias is to "provide[] a consistent method for calculating the Frequency Bias component of [Area Control Error (ACE)]." Requirements R2 and R2.2 of this standard addresses the maintenance of a frequency bias setting close to the Balancing Authority's natural frequency response and offers options on its calculation. Requirement R5 and R5.1 establishes a complementary requirement to maintain a monthly average frequency bias setting at least 1% of the estimated yearly peak demand or maximum generation level per

0.1 Hz change depending upon the nature of the Balancing Authority. The specific language of these requirements is:

> **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:
>
> > **R2.2.** 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.
>
> **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.

On May 31, 2007, the Electric Reliability Council of Texas ("ERCOT") requested that NERC provide a formal interpretation of BAL-003-0 — Frequency Response and Bias: Requirements R2, R2.2, R5 and R5.1, respectively. Specifically, ERCOT requested clarification that a Balancing Authority is entitled to use a variable bias value as authorized in Requirement R2.2, even though Requirement R5 does not seem to account for the possibility of variable bias settings. ERCOT submitted that if a Balancing Authority uses a variable bias in conformance with Requirement R2.2, it would violate Requirement R5 if the analysis resulted in any value less than 1% of its yearly peak demand (or maximum generation). ERCOT further asserted that Requirement R2.2 is only viable if NERC interprets Requirement R5 to only apply to Balancing Authorities that use a fixed bias setting. The correct corresponding measure for a variable bias setting would be no less than 1% of the Balancing Authority's estimated peak (or maximum generation) for the period in which the bias setting is active. ERCOT further noted its interpretation of this issue is consistent with NERC's Resources Subcommittee analysis in January 2003 that "for Control Areas utilizing variable bias, the Control Area's average Bias Setting for a month must be at least 1 % of the Control Area's estimated peak load for that month (or 1 % of peak generation for a generation only Control Area forecast for that month)."[1]

ERCOT requested the interpretation because the lack of a variable-bias option under Requirement R5 appears to be an oversight. An incorrect interpretation would force ERCOT to abandon its longstanding and approved practice of using a variable setting without any corresponding improvement in reliability.[2]

NERC assigned its Resources Subcommittee to provide the requested interpretation. In its response, the Resources Subcommittee stated that Requirement R2 does not conflict with Requirement R5. Requirement R2 requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting. The setting may be a fixed or variable bias.

Requirement R5 sets a minimum contribution for all Balancing Authorities toward stabilizing interconnection frequency. The 1% bias setting establishes a minimum level of automatic generation control action to help stabilize frequency following a disturbance. By setting a floor on bias, Requirement R5 also helps ensure a consistent measure of control performance among all Balancing Authorities within a multi-Balancing Authority interconnection. As a single Balancing Authority interconnection, ERCOT uses bias settings that do produce, on average, the best level of automatic

[1] *See* ERCOT Request for Interpretation at 1-2 (http://www.nerc.com/docs/standards/sar/Request_Interpretation_BAL-003_ERCOT_27Jul07.pdf)
[2] *Id.* at 2-3.

generation control action to meet control performance metrics. The bias value in a single Balancing Authority interconnection does not impact the measure of control performance.

To add further context to this issue, although not part of the formal interpretation to be appended to the BAL-003-0 Reliability Standard, ERCOT requested and received approval from NERC and ultimately FERC in Order No. 693 for a waiver to Requirement R2 of BAL-001-0 – Real Power Balancing Control Performance, more commonly referred to as CPS2. The basis for this exemption is rooted in ERCOT's asynchronous connections to the other interconnections and the fact that section 5 of ERCOT protocols establishes a more stringent methodology to identify the frequency controls necessary to maintain reliable operations.

NERC believes that the interpretation as presented directly supports the reliability purpose of the standard, that is, to provide a consistent method for calculating the Frequency Bias component of ACE. This interpretation provides clarity and certainty to ERCOT as they implement their protocols in support of this important reliability objective.

b. Summary of the Reliability Standard Development Proceedings

On May 31, 2007, ERCOT requested a formal interpretation of Requirements R2, R2.2, R5 and R5.1 of BAL-003-0. 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 27, 2007 – August 27, 2007. NERC conducted an initial ballot from August 27, 2007 – September 5, 2007, but two negative votes were 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 September 20, 2007 – September 29, 2007. The formal interpretation was approved by the ballot pool with a weighted segment average of 96.26%, with 85.90% of the ballot pool voting.

Two sets of comments were received during the ballot process tied to a negative ballot. One of the commenters indicated that Requirement R5 is too vague. The Resources Subcommittee agreed that there is better wording to state all Balancing Authorities must have a monthly average bias greater than or equal to 1% of its projected annual peak load (or generation if it does not serve load). However, changing the language in a requirement is beyond the scope of the interpretation process.

The second comment submitted with a negative ballot requested further clarification on the interpretation of Requirement R5. The commenter asked if a Balancing Authority that was the sole Balancing Authority for an interconnection needs to comply with Requirement R5, and also asked if a Balancing Authority that uses a variable bias setting needs to comply with Requirement R5 in BAL-003-0. The Resources Subcommittee responded that both must comply with Requirement R5.

V. VAR-001-1 —Voltage and Reactive Control, Requirement R4

In Section V(a), NERC explains the need for and development of the formal interpretation of VAR-001-1 — Voltage and Reactive Control, Requirement R4. In addition, NERC demonstrates that the formal interpretation is consistent with the stated reliability goal of the Reliability Standard 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.

a. Justification for Approval of Formal Interpretation

The stated purpose of VAR-001-1 — Voltage and Reactive Control is "[t]o ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection." Requirement R4 states:

> **R4.** 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).

On October 11, 2007, NERC received a request from Dynegy to provide a formal interpretation of Requirement R4. Dynegy specifically requests:

> *The current wording of Requirement [R]4 of NERC Reliability Standard VAR-001-1 does not impose any explicit obligations on the Transmission Operator other than to provide the Generator Operator with a voltage or reactive power output schedule and an associated tolerance band.*
>
> *Dynegy believes that Requirement R4 of NERC Reliability Standard VAR-001-1 requires interpretation. The specific questions that need to be answered are the following:*

1. Is the Transmission Operator implicitly required to have a technical basis for specifying the voltage or reactive power schedule and associated tolerance band?

2. Is the Transmission Operator implicitly required to issue a voltage or reactive power schedule and associated tolerance band that is reasonable and practical for the Generator Operator to maintain?

3. What measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band?[3]

NERC requested that members of the Phase III and IV Standard Drafting Team that originally developed the VAR-001-1 standard develop the interpretation.

The team provided the following response to the interpretation request:

NERC Reliability Standard VAR-001-1 is only comprised of stated requirements and associated compliance elements. The requirements have been developed in a fair and open process, balloted and accepted by FERC for compliance review. Any "implicit" requirement would be based on subjective interpretation and viewpoint and therefore cannot be objectively measured and enforced. Any attempt at "interpreting an implicit requirement" would effectively be adding a new requirement to the standard. This can only be done through the SAR (standards authorization request) process.

Since there are no requirements in VAR-001-1 to issue a "technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band", there are no measures or associated compliance elements in the standard.

The standard only requires that "Each Transmission Operator shall specify a voltage or Reactive Power schedule…." and that "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….". Also, Measure 1 and the associated compliance elements follow accordingly by stating that "The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule …."

Requirement 2 and Requirement 2.2 of VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules relate somewhat to questions #2 and 3. Requirement R2 states that "Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power

[3] *See* ERCOT Request for Interpretation at 2. (http://www.nerc.com/docs/standards/sar/VAR-001-1_Request_Interpretation_Dynegy_11Oct07.pdf)

> *output (within applicable Facility Ratings[]) as directed by the Transmission Operator." R2.2 goes on to state "When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met."*

When this proposed interpretation was presented to the NERC Board of Trustees for approval at its February 2008 meeting, it elected to defer action at that time pending further information. The Board of Trustees expressed concern that the Generator Operator could be in violation of a standard requirement, and hence subject to penalty, by not adhering to the voltage schedule directed by its Transmission Operator in order to protect its equipment. In response to this question, NERC staff provided the following additional information to allay this concern. Note that this additional information is not intended to be included as a portion of the formal interpretation proposed for approval in this filing.

The concern about a Generator Operator adhering to a Transmission Operator voltage schedule directive at the risk of generating unit damage is alleviated through reliability requirements contained in VAR-002-1a – Generator Operation for Maintaining Network Voltage Schedules, the companion reliability standard to VAR-001-1 that is the subject of this proposed interpretation.

The purpose of Reliability Standard VAR-002-1a – Generator Operation for Maintaining Network Voltage Schedules states:

> To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained <u>*within applicable Facility Ratings to protect equipment*</u> and the reliable operation of the Interconnection." (emphasis added)

In particular, Requirement R2 states that, "[u]nless 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." Sub-requirement R2.2 goes on to state that "[w]hen directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met."

The term *Facility Rating* is defined in NERC's Glossary of Terms as approved by the Commission as "[t]he maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that *does not violate the applicable equipment rating of any equipment comprising the facility*." (emphasis added)

Therefore, as prescribed in Requirement R2 of VAR-002-1a, the Generator Operator shall comply with the request of the Transmission Operator only to the extent to which compliance with the directive does not exceed the applicable equipment rating for the generator. When a Generator Operator is not able to comply with the Transmission Operator directive, the Generator Operator must notify and explain to the Transmission Operator why the schedule cannot be met, per Requirement R2.2.

Based on the foregoing information, the NERC Board of Trustees subsequently approved the interpretation of Requirement R4 of VAR-001-1 — Voltage and Reactive Control on March 26, 2008.

In addition to the formal interpretation requested for approval and the supplemental information provided at the request of the NERC Board of Trustees, NERC offers the following discussion as further context to the question raised by Dynegy. This information is intended to be instructive to the issue presented. NERC supports the formal interpretation as presented in this filing. However, Requirement R2 of the VAR-001-1 Reliability Standard states:

> Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

A Transmission Operator is obligated to acquire sufficient reactive resources to protect voltage levels under normal and contingency conditions. In order for a Transmission Operator to ascertain the reactive resources necessary to protect its voltage levels, it must first identify what voltage levels are acceptable under normal and contingency conditions. One could reasonably assume that the Transmission Operator would be required to analyze the system for which it is responsible for operating in a forward-looking manner to ensure the reactive infrastructure is in place to support operation as expected, both under normal operating conditions and under contingency conditions. In order to analyze the system, the Transmission Operator would need to have system models that includes accurate representations of the equipment and characteristics associated with that equipment to ensure the validity of the analysis. In this regard, although Requirement R4 of VAR-001-1 as interpreted is correct, more insight into this question can be found through examination of Requirement R2 of this same standard.

NERC believes the formal interpretation and supporting discussion clearly state that a requirement cannot establish implicit obligations as suggested in the original request for interpretation. Further, the interpretation reinforces that the Transmission Operator is responsible to identify the voltage schedules and associated bandwidth necessary to meet the objectives of the Reliability Standard. Thus, this interpretation directly supports the intent of the requirement and the goal of the VAR-001-1 standard.

b. Summary of the Reliability Standard Development Proceedings

On October 11, 2007, NERC received a request for formal interpretation of Requirement R4 of the VAR-001-1 Reliability Standard. NERC selected members of the Phase III/IV standard drafting team that authored the Reliability Standard to prepare the interpretation. NERC published the formal interpretation for a 30-day pre-ballot review that started on November 5, 2007. The initial ballot was conducted from December 4, 2007 – December 13, 2007 and achieved a quorum and sufficient affirmative ballots for passage, but there were five negative ballots cast with comments, necessitating a recirculation ballot.

- Four balloters indicated they agreed with the interpretation, but believed the interpretation process should not have been used since it was obvious that the question being asked was not within the requirements of the standard. NERC agrees that careful scrutiny should be exercised when fielding requests for interpretation to ensure they are appropriate for response.
- One balloter indicated that he disagreed with the interpretation, and believed that the standard's requirements do imply that there will be a technical justification for a reactive power schedule. The team disagreed and indicated that the use of the term "implied" is not a stated requirement that can be objectively measured.

NERC conducted the recirculation ballot from January 14, 2008 – January 23, 2008. The interpretations passed with a quorum of 89.67% and a weighted segment approval of 93.18 %.

Respectfully submitted,

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Exhibit A-1

Formal interpretation

BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5 and R5.1

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5, and R5.1

Request for Interpretation received from ERCOT on May 31, 2007:

ERCOT specifically requests clarification that a Balancing Authority is entitled to use a variable bias value as authorized by Requirement R2.2, even though Requirement 5 seems not to account for the possibility of variable bias settings

Interpretation provided by NERC Resources Subcommittee on July 25, 2007:

The consensus of the Resources Subcommittee is that BAL-003-0 — Frequency Response and Bias — Requirement R2 does not conflict with BAL-003-0 Requirement R5.

BAL-003-0 — Frequency Response and Bias Requirement 2 requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting. The Balancing Authority may then choose a fixed bias (constant through the year) per Requirement 2.1, or a variable bias (varies with load, specific generators, etc.) per Requirement 2.2.

BAL-003-0

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.

BAL-003-0 — Frequency Response and Bias Requirement 5 sets a minimum contribution for all Balancing Authorities toward stabilizing interconnection frequency. The 1% bias setting establishes a minimum level of automatic generation control action to help stabilize frequency following a disturbance. By setting a floor on bias, Requirement 5 also helps ensure a consistent measure of control performance among all Balancing Authorities within a multi-Balancing Authority interconnection. However, ERCOT is a single Balancing Authority interconnection. The bias settings ERCOT uses do produce, on average, the best level of automatic generation control action to meet control performance metrics. The bias value in a single Balancing Authority interconnection does not impact the measure of control performance.

BAL-003-0

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.

Exhibit B-1

Formal interpretation

VAR-001-1 — Voltage and Reactive Control, Requirement R4

Interpretation of NERC Standard VAR-001-1 — Voltage and Reactive Control, Requirement R4

Request for Interpretation received from Dynegy on October 11, 2007:

The current wording of VAR-001-1 Requirement 4 does not impose any explicit obligations on the Transmission Operator other than to provide the Generator Operator with a voltage or reactive power output schedule and an associated tolerance band.

1. *Is the Transmission Operator implicitly required to have a technical basis for specifying the voltage or reactive power and associated tolerance band?*
2. *Is the Transmission Operator implicitly required to issue a voltage or reactive power schedule and associated tolerance band that is reasonable and practical for the Generator Operator to maintain?*
3. *What measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band?*

VAR-001-1

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule[1] 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).

[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

Interpretation provided by members of the Phase III & IV Standard Drafting Team on October 30, 2007:

NERC Reliability Standard VAR-001-1 is only comprised of stated requirements and associated compliance elements. The requirements have been developed in a fair and open process, balloted and accepted by FERC for compliance review. Any "implicit" requirement would be based on subjective interpretation and viewpoint and therefore cannot be objectively measured and enforced. Any attempt at "interpreting an implicit requirement" would effectively be adding a new requirement to the standard. This can only be done through the SAR process.

Since there are no requirements in VAR-001-1 to issue a "technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band", there are no measures or associated compliance elements in the standard.

The standard only requires that "Each Transmission Operator shall specify a voltage or Reactive Power schedule …." and that "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….”. Also, Measure 1 and the associated compliance elements follow accordingly by stating that “The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule …”

VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules

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.

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.

Requirement 2 and Requirement 2.2 of VAR-002-1 relate somewhat to questions #2 and 3. R2 states that “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.” R2.2 goes on to state “When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.”

Exhibit A-2

Affected Reliability Standard that includes the appended interpretation

BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5 and R5.1

A. Introduction

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

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

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.

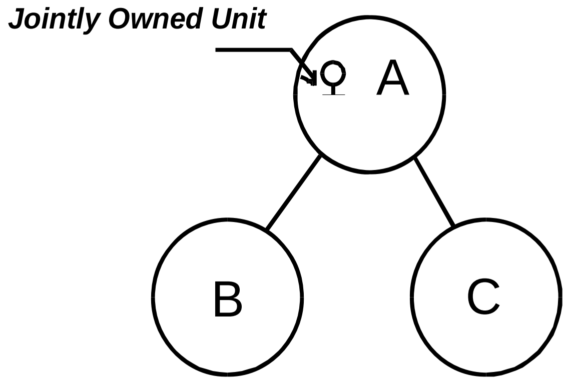
R2.2. The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such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

1. Appendix 1 – Interpretation of Requirement R3 (October 23, 2007).
2. Appendix 2 – Interpretation of Requirements R2, R2.2, R5, and R5.1 (February 12, 2008).

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	Addition

0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial.	Errata
0a	February 12, 2008	Added Appendix 2 – Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition

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:

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

Appendix 2

Interpretation of Requirements R2, R2.2, R5, R5.1

Request: *ERCOT specifically requests clarification that a Balancing Authority is entitled to use a variable bias value as authorized by Requirement R2.2, even though Requirement 5 seems not to account for the possibility of variable bias settings.*

Interpretation:

The consensus of the Resources Subcommittee is that BAL-003-0 — Frequency Response and Bias — Requirement R2 does not conflict with BAL-003-0 Requirement R5.

BAL-003-0 — Frequency Response and Bias Requirement 2 requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting. The Balancing Authority may then choose a fixed bias (constant through the year) per Requirement 2.1, or a variable bias (varies with load, specific generators, etc.) per Requirement 2.2.

BAL-003-0

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.

BAL-003-0 — Frequency Response and Bias Requirement 5 sets a minimum contribution for all Balancing Authorities toward stabilizing interconnection frequency. The 1% bias setting establishes a minimum level of automatic generation control action to help stabilize frequency following a disturbance. By setting a floor on bias, Requirement 5 also helps ensure a consistent measure of control performance among all Balancing Authorities within a multi-Balancing Authority interconnection. However, ERCOT is a single Balancing Authority interconnection. The bias settings ERCOT uses do produce, on average, the best level of automatic generation control action to meet control performance metrics. The bias value in a single Balancing Authority interconnection does not impact the measure of control performance.

BAL-003-0

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.

Exhibit B-2

Affected Reliability Standard that includes the appended interpretation

VAR-001-1 — Voltage and Reactive Control, Requirement R4

A. Introduction

1. **Title:** **Voltage and Reactive Control**

2. **Number:** VAR-001-1

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Purchasing-Selling Entities.

5. **Effective Date:** Six months after BOT adoption.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

R3.1. Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.

R3.2. For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] 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).

R5. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

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 Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

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

1.4. Additional Compliance Information

The Transmission Operator shall 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

2.1. Level 1: No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2

2.2. Level 2: There shall be a level two non-compliance if either of the following conditions exists:

2.2.1 No evidence to show that directives were issued in accordance with R6.1.

2.2.2 No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with R11.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions exists:

2.3.1 Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.

2.4. Level 4: No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	July 3, 2007	Added "Generator Owners" and "Generator Operators" to Applicability section.	Errata
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata
1a	March 26, 2008	Added Appendix 1 – Interpretation of R4 approved by BOT on March 26, 2008.	Revised

Appendix 1

Interpretation of Requirement 4

Request:

The current wording of VAR-001-1 Requirement 4 does not impose any explicit obligations on the Transmission Operator other than to provide the Generator Operator with a voltage or reactive power output schedule and an associated tolerance band.

1. *Is the Transmission Operator implicitly required to have a technical basis for specifying the voltage or reactive power and associated tolerance band?*
2. *Is the Transmission Operator implicitly required to issue a voltage or reactive power schedule and associated tolerance band that is reasonable and practical for the Generator Operator to maintain?*
3. *What measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band?*

VAR-001-1

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule[1] 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).

[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

Interpretation:

NERC Reliability Standard VAR-001-1 is only comprised of stated requirements and associated compliance elements. The requirements have been developed in a fair and open process, balloted and accepted by FERC for compliance review. Any "implicit" requirement would be based on subjective interpretation and viewpoint and therefore cannot be objectively measured and enforced. Any attempt at "interpreting an implicit requirement" would effectively be adding a new requirement to the standard. This can only be done through the SAR process.

Since there are no requirements in VAR-001-1 to issue a "technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band", there are no measures or associated compliance elements in the standard.

The standard only requires that "Each Transmission Operator shall specify a voltage or Reactive Power schedule …." and that "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….". Also, Measure 1 and the associated compliance elements follow accordingly by stating that "The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule …"

VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules

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.

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.

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

Exhibit A-3

The complete development record of the formal interpretation

BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5 and R5.1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

ERCOT Request for Interpretation - BAL-003

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

Status
Approved by the NERC Board of Trustees on October 23, 2007 and pending regulatory approval.

Purpose/Industry Need
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.

Proposed Standard	Supporting Documents	Comment Period	Comments Received	Response to Comments
Request for Interpretation BAL-003-0, R2, 2.2, 5, and 5.1 Adopted by Board of Trustees on October 23, 2007 BAL-003 Interpretation **(12)**				
Announcement **(9)** Request for Interpretation BAL-003-0, R2, 2.2, 5, and 5.1 Posted for 10-day Recirculation Ballot Window BAL-003 Interpretation **(same as #1)**	ERCOT Request for Interpretation **(same as #2)** BAL-003-0, R2. 2.2, 5, and 5.1	09/20/07 - 09/29/07 (closed)		Announcement **(10)** Recirculation Ballot Results **(11)**
ERCOT Interpretation WebEx and Conference Call Agenda - September 18, 2007 **(8)**				
Announcement **(4)** Request for	ERCOT Request for Interpretation **(same as #2)**	08/27/07 - 09/05/07 (closed)		Announcement **(5)**

Interpretation BAL-003-0, R2, 2.2, 5, and 5.1 Posted for 10-day Ballot Window BAL-003 Interpretation **(same as #1)**	BAL-003-0, R2. 2.2, 5, and 5.1			Initial Ballot Summary **(6)** Consideration of Initial Ballot Comments **(7)**
Announcement **(3)** Request for Interpretation BAL-003-0, R2, 2.2, 5, and 5.1 Posted for 30-day Pre-ballot Review BAL-003 Interpretation **(1)**	ERCOT Request for Interpretation **(2)** BAL-003-0, R2. 2.2, 5, and 5.1	07/27/07 - 08/27/07 (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.net.
Questions? Contact Barbara Bogenrief - barbara.bogenrief@nerc.net or 609-452-8060.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5, and R5.1

Request for Interpretation received from ERCOT on May 31, 2007:

ERCOT specifically requests clarification that a Balancing Authority is entitled to use a variable bias value as authorized by Requirement R2.2, even though Requirement 5 seems not to account for the possibility of variable bias settings

Interpretation provided by NERC Resources Subcommittee on July 25, 2007:

The consensus of the Resources Subcommittee is that BAL-003-0 — Frequency Response and Bias — Requirement R2 does not conflict with BAL-003-0 Requirement R5.

BAL-003-0 — Frequency Response and Bias Requirement 2 requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting. The Balancing Authority may then choose a fixed bias (constant through the year) per Requirement 2.1, or a variable bias (varies with load, specific generators, etc.) per Requirement 2.2.

BAL-003-0

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.

BAL-003-0 — Frequency Response and Bias Requirement 5 sets a minimum contribution for all Balancing Authorities toward stabilizing interconnection frequency. The 1% bias setting establishes a minimum level of automatic generation control action to help stabilize frequency following a disturbance. By setting a floor on bias, Requirement 5 also helps ensure a consistent measure of control performance among all Balancing Authorities within a multi-Balancing Authority interconnection. However, ERCOT is a single Balancing Authority interconnection. The bias settings ERCOT uses do produce, on average, the best level of automatic generation control action to meet control performance metrics. The bias value in a single Balancing Authority interconnection does not impact the measure of control performance.

BAL-003-0

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.

ERCOT
THE TEXAS CONNECTION

May 31, 2007

Sent Via E-Mail and First-Class U.S. Mail

Ms. Maureen E. Long
Standards Process Manager
The North American Electric Reliability Corporation
Princeton Forrestal Village
115 Village Boulevard
Princeton, New Jersey 08540-5731

Subject: Request for Interpretation of NERC Standard BAL-003-0 Requirements R2, R 2.2, R5, and R5.1

Dear Ms. Long:

Pursuant to the North American Electric Reliability Corporation (NERC) Reliability Standards Development Procedure (RSDP),[1] the Electric Reliability Council of Texas, Inc. (ERCOT) respectfully requests an interpretation of the above-referenced standard. ERCOT specifically requests clarification that a Balancing Authority (BA) is entitled to use a variable bias value as authorized by Requirement R2.2, even though Requirement R5 seems not to account for the possibility of variable bias settings.

Four specific requirements under NERC Standard BAL-003-0 are relevant to this request:

- NERC Standard BAL-003-0, Requirement R2 states: "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 …."

- Requirement R2.2 further states: "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."

- Requirement R5 states: "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."

[1] Version 6.0, adopted by the NERC Board of Trustees on Nov. 1, 2006, at 26-27.

Austin
7620 Metro Center Drive
Austin, Texas 78744
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2705 West Lake Drive
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- Requirement R5.1 further states: "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."

ERCOT submits that, if a BA uses a variable bias in conformance with R2.2, it would violate R5 if the analysis results in any value less than 1% of its yearly peak demand (or maximum generation). R2.2 is a legitimate option sanctioned by NERC and by the Federal Energy Regulatory Commission, and ERCOT sets its bias using this method. We would respectfully further assert that R2.2 is only viable if NERC interprets R5 to only apply to BAs that use a fixed bias setting. The correct corresponding measure for a variable bias setting would be no less than 1% of the BA's estimated peak (or maximum generation) for the period in which the bias setting is active.

ERCOT's requested interpretation is consistent with a previous NERC Reliability Subcommittee (RS) interpretation, as noted in the RS's January 2003 minutes:

> Resources Subcommittee Meeting Minutes
> January 29-31, 2003
> Variable Non-Linear Bias
> During the last subcommittee meeting, the following motion was passed: The Resources Subcommittee interprets Standard 1.1.4, "Control Area's monthly average Frequency Bias Setting must be at least 1% of the Control Area's estimated yearly peak demand per 0.1 Hz change" requirement to be applicable to all Control Areas that contain load and that use bias settings. The subcommittee discussed and interpreted last meeting's motion to address only fixed bias, not variable bias. Variable bias needs to be addressed.
>
> After discussion, Don Badley made a motion as follows: The Resources Subcommittee interprets Standard 1.1.4 for Control Areas utilizing variable bias, the Control Area's average Bias Setting for a month must be at least 1% of the Control Area's estimated peak load for that month (or 1% of peak generation for a generation only Control Area forecast for that month). The motion was approved.

An interpretation under NERC's RSDP is appropriate because the lack of a variable-bias option under Requirement R5 appears to be an oversight, and the RSDP specifically provides that interpretations are appropriate to identify clarifications that correct oversights in the Standards until such time as the standard at issue can be "revised through the normal process … to incorporate the clarifications provided by the interpretation." This interpretation is important to ERCOT and should be important to any BA using a variable bias setting, because an incorrect interpretation would force

ERCOT to abandon its longstanding and approved practice of using a variable setting, without any corresponding improvement in reliability.

For the foregoing reasons, ERCOT respectfully requests an interpretation that clarifies the requirements of this Standard.

Sincerely,

H Steven Myers

H. Steven Myers
ERCOT
Manager, Operating Standards

Maureen E. Long
Standards Process Manager

July 27, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Pre-ballot Window and Ballot Pool Open July 27, 2007

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

Pre-ballot Window and Ballot Pool for Interpretation of BAL-003-0 Requirements R2, R2.2, R5, and R5.1 both Open July 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.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EDT) Monday, August 27, 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-bp_interpret_bal-003_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EDT) on Monday, August 27, 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

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

October 1, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement of Final Ballot Results

The Standards Committee (SC) announces the following:

Final Ballot Results for Interpretation of BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5, and R5.1

The recirculation ballot for the interpretation of BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5 and R5.1 was conducted from September 20–29, 2007 and the ballot passed. (Detailed Ballot Results)

The Electric Reliability Council of Texas (ERCOT) submitted a Request for an Interpretation of BAL-003-0 — Frequency Response and Bias Requirements R2, R2.2, R5, and R5.1. The request asked if there was a conflict between Requirement R2, which allows use of a variable bias setting, and Requirement R5, which does not specifically address the use of a variable bias setting.

Quorum: 85.90 %
Approval: 96.26 %

The Interpretation clarifies that in reliability standard BAL-003-0, Requirements R2 and R5 do not conflict with one another.

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 - BAL-003 - ERCOT_in
Ballot Period:	8/27/2007 - 9/5/2007
Ballot Type:	Initial
Total # Votes:	134
Total Ballot Pool:	156
Quorum:	**85.90 % The Quorum has been reached**
Weighted Segment Vote:	96.15 %
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.	42	1	25	1	0	0	13	4
2 - Segment 2.	10	0.8	8	0.8	0	0	1	1
3 - Segment 3.	36	1	27	1	0	0	5	4
4 - Segment 4.	10	0.4	4	0.4	0	0	2	4
5 - Segment 5.	24	1	16	1	0	0	2	6
6 - Segment 6.	18	1	11	0.846	2	0.154	3	2
7 - Segment 7.	1	0.1	1	0.1	0	0	0	0
8 - Segment 8.	3	0.2	1	0.1	1	0.1	0	1
9 - Segment 9.	7	0.7	7	0.7	0	0	0	0
10 - Segment 10.	5	0.4	4	0.4	0	0	1	0
Totals	**156**	**6.6**	**104**	**6.346**	**3**	**0.254**	**27**	**22**

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	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Duke Energy	Doug Hils		
1	East Kentucky Power Coop.	George S. Carruba		
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Power & Light Co.	C. Martin Mennes	Abstain	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	

1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
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	Manitoba Hydro	Robert G. Coish	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Abstain	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Abstain	
1	New York Power Authority	Ralph Rufrano	Abstain	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Joseph Dobes	Abstain	
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	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		
1	Sacramento Municipal Utility District	Dilip Mahendra	Abstain	View
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	Southern California Edison Co.	Dana Cabbell	Abstain	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Coop., Inc.	Alan H. Wilkinson	Affirmative	
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	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Robert Temple	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper		
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Affirmative	
2	Independent Electricity System Operator	Don Tench	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Abstain	
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	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Burbank Water and Power	Xavier G. Baldwin	Affirmative	
3	City of Tallahassee	Rusty S. Foster	Abstain	
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	Abstain	
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 & Light Co.	W.R. Schoneck	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Gulf Power Company	William F. Pope	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Abstain	
3	JEA	Garry Baker		
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	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		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Cynthia Herron	Affirmative	
3	Tri-State G & T Association Inc.	Dillwyn H. Ramsay	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Consumers Energy Co.	David Frank Ronk	Affirmative	
4	Florida Municipal Power Agency	William S. May	Affirmative	
4	LaGen	Keith Comeaux		
4	LaGen	Richard Comeaux		
4	LaGen	Keith Comeaux		
4	LaGen	Richard Comeaux		
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 2 of Grant County	Kevin J. Conway	Abstain	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Alabama Electric Coop. Inc.	Tim Hattaway	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin		
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus		
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	East Kentucky Power Coop.	Gerard Bordes		
5	Florida Municipal Power Agency	Douglas Keegan	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	New York Power Authority	Richard J. Ardolino	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Abstain	

5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Southeastern Power Administration	Douglas Spencer		
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	Xcel Energy, Inc.	Stephen J. Beuning	Affirmative	
6	AEP Service Corp.	Dana E. Horton	Affirmative	
6	Entergy Services, Inc.	William Franklin	Negative	View
6	First Energy Solutions	Alfred G. Roth	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Abstain	
6	Powerex Corp.	Daniel W. O'Hearn	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
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	Tennessee Valley Authority	Katherine E. York	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Eastman Chemical Company	Lloyd Webb	Affirmative	
8	Energy Mark, Inc.	Howard F. Illian		
8	JDRJC Associates	Jim D. Cyrulewski	Negative	View
8	Other	Michehl R. Gent	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maryland Public Service Commission	James Schafer	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher	Affirmative	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	SERC Reliability Corporation	Gerry W. Cauley	Affirmative	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Abstain	

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

Consideration of Comments on Initial Ballot of Interpretation of BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5, and R5.1

Summary Consideration: The drafting team (Resources Subcommittee) did not make any changes based on the comments received during the initial ballot for the interpretation of BAL-003-0 Requirements R2, R2.2, R5 and R5.1.

Segment	Organization	Comment
6	Entergy Services, Inc.	The interpretation of Requirement 5 states that the floor bias setting establishes a minimum level of AGC and also ensures a consistent measure of control performance. It is not clear as to why the Resources Subcommittee believes that ERCOT need not meet the floor requirement on the bias setting - is it because they use a variable bias or is it because they are a single BA Interconnection, or both? It appears that the interpretation needs an interpretation. The interpretation of R5 should explicity address whether or not that BAs that are either: a single BA Interconnect, or using variable bias, are subject to R5.
Response: The Resources Subcommittee (RS) was providing background on the logic for having a minimum bias obligation. The RS does believe that ERCOT needs to meet the floor requirement on the bias setting. Both a single Balancing Authority Interconnection and a Balancing Authority using a variable bias are subject to Requirement R5.		
8	JDRJC Associates	Requirement 5 needs further clarification.
Response: We agree there are better ways to say that all Balancing Authorities must have a monthly average Bias greater than or equal to 1% of its projected annual peak load (or generation if it does not serve load).		

September 19, 2007

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

BAL-003 R2, R2.2, R5, and R5.1 Interpretation Drafting Team Meeting

September 18, 2007 — 11 a.m. Eastern Daylight Time

Web Conference Agenda

Consortium conference server: 1(732)694-2061
Conference code: 104109182

Web Ex Meeting Number: 717 852 387
Meeting password: BAL003

1) Administrative
   a) Introduction of Participants
   b) Review Antitrust Guidelines (Attachment 1)
   c) Review Meeting Objectives:
      i) Prepare Response to Comments
2) Review & Revise Interpretation Response
   a) Review PGE Request for Interpretation (Attachment 2)
   b) Review Interpretation of BAL-003 (Attachment 3)
   c) Prepare Response to Comments (Attachment 4)
3) Discuss Next Steps

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

NERC Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

ERCOT
THE TEXAS CONNECTION

May 31, 2007

Sent Via E-Mail and First-Class U.S. Mail

Ms. Maureen E. Long
Standards Process Manager
The North American Electric Reliability Corporation
Princeton Forrestal Village
115 Village Boulevard
Princeton, New Jersey 08540-5731

Subject: Request for Interpretation of NERC Standard BAL-003-0 Requirements R2, R 2.2, R5, and R5.1

Dear Ms. Long:

Pursuant to the North American Electric Reliability Corporation (NERC) Reliability Standards Development Procedure (RSDP),[1] the Electric Reliability Council of Texas, Inc. (ERCOT) respectfully requests an interpretation of the above-referenced standard. ERCOT specifically requests clarification that a Balancing Authority (BA) is entitled to use a variable bias value as authorized by Requirement R2.2, even though Requirement R5 seems not to account for the possibility of variable bias settings.

Four specific requirements under NERC Standard BAL-003-0 are relevant to this request:

- NERC Standard BAL-003-0, Requirement R2 states: "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 …."

- Requirement R2.2 further states: "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."

- Requirement R5 states: "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."

[1] Version 6.0, adopted by the NERC Board of Trustees on Nov. 1, 2006, at 26-27.

Austin
7620 Metro Center Drive
Austin, Texas 78744
Tel. 512. 225. 7000 | Fax 512. 225. 7020

Taylor
2705 West Lake Drive
Taylor, Texas 76574
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- Requirement R5.1 further states: "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."

ERCOT submits that, if a BA uses a variable bias in conformance with R2.2, it would violate R5 if the analysis results in any value less than 1% of its yearly peak demand (or maximum generation). R2.2 is a legitimate option sanctioned by NERC and by the Federal Energy Regulatory Commission, and ERCOT sets its bias using this method. We would respectfully further assert that R2.2 is only viable if NERC interprets R5 to only apply to BAs that use a fixed bias setting. The correct corresponding measure for a variable bias setting would be no less than 1% of the BA's estimated peak (or maximum generation) for the period in which the bias setting is active.

ERCOT's requested interpretation is consistent with a previous NERC Reliability Subcommittee (RS) interpretation, as noted in the RS's January 2003 minutes:

> Resources Subcommittee Meeting Minutes
> January 29-31, 2003
> Variable Non-Linear Bias
> During the last subcommittee meeting, the following motion was passed: The Resources Subcommittee interprets Standard 1.1.4, "Control Area's monthly average Frequency Bias Setting must be at least 1% of the Control Area's estimated yearly peak demand per 0.1 Hz change" requirement to be applicable to all Control Areas that contain load and that use bias settings. The subcommittee discussed and interpreted last meeting's motion to address only fixed bias, not variable bias. Variable bias needs to be addressed.
>
> After discussion, Don Badley made a motion as follows: The Resources Subcommittee interprets Standard 1.1.4 for Control Areas utilizing variable bias, the Control Area's average Bias Setting for a month must be at least 1% of the Control Area's estimated peak load for that month (or 1% of peak generation for a generation only Control Area forecast for that month). The motion was approved.

An interpretation under NERC's RSDP is appropriate because the lack of a variable-bias option under Requirement R5 appears to be an oversight, and the RSDP specifically provides that interpretations are appropriate to identify clarifications that correct oversights in the Standards until such time as the standard at issue can be "revised through the normal process … to incorporate the clarifications provided by the interpretation." This interpretation is important to ERCOT and should be important to any BA using a variable bias setting, because an incorrect interpretation would force

ERCOT to abandon its longstanding and approved practice of using a variable setting, without any corresponding improvement in reliability.

For the foregoing reasons, ERCOT respectfully requests an interpretation that clarifies the requirements of this Standard.

Sincerely,

H Steven Myers

H. Steven Myers
ERCOT
Manager, Operating Standards

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5, and R5.1

Request for Interpretation received from ERCOT on May 31, 2007:

ERCOT specifically requests clarification that a Balancing Authority is entitled to use a variable bias value as authorized by Requirement R2.2, even though Requirement 5 seems not to account for the possibility of variable bias settings

Interpretation provided by NERC Resources Subcommittee on July 25, 2007:

The consensus of the Resources Subcommittee is that BAL-003-0 — Frequency Response and Bias — Requirement R2 does not conflict with BAL-003-0 Requirement R5.

BAL-003-0 — Frequency Response and Bias Requirement 2 requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting. The Balancing Authority may then choose a fixed bias (constant through the year) per Requirement 2.1, or a variable bias (varies with load, specific generators, etc.) per Requirement 2.2.

BAL-003-0

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.

BAL-003-0 — Frequency Response and Bias Requirement 5 sets a minimum contribution for all Balancing Authorities toward stabilizing interconnection frequency. The 1% bias setting establishes a minimum level of automatic generation control action to help stabilize frequency following a disturbance. By setting a floor on bias, Requirement 5 also helps ensure a consistent measure of control performance among all Balancing Authorities within a multi-Balancing Authority interconnection. However, ERCOT is a single Balancing Authority interconnection. The bias settings ERCOT uses do produce, on average, the best level of automatic generation control action to meet control performance metrics. The bias value in a single Balancing Authority interconnection does not impact the measure of control performance.

BAL-003-0

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.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot of Interpretation of BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5, and R5.1

Segment	Organization	Comment
6	Entergy Services, Inc.	The interpretation of Requirement 5 states that the floor bias setting establishes a minimum level of AGC and also ensures a consistent measure of control performance. It is not clear as to why the Resources Subcommittee believes that ERCOT need not meet the floor requirement on the bias setting - is it because they use a variable bias or is it because they are a single BA Interconnection, or both? It appears that the interpretation needs an interpretation. The interpretation of R5 should explicity address whether or not that BAs that are either: a single BA Interconnect, or using variable bias, are subject to R5.
Response: The Resources Subcommittee (RS) was ~~just~~ providing background on the ~~original~~ logic for having a minimum bias obligation. ~~While the RS believes a bias floor makes more sense in a multi-BA environment, the intent of doing an interpretation of the standard is to interpret what was written, not what we would like the standard to be~~[ljc1]~~.~~		
8	JDRJC Associates	Requirement 5 needs further clarification.
Response: We agree there are better ways to say that all BAs must have a monthly average Bias greater than or equal to 1% of its projected annual peak load (or generation if it does not serve load).		

Maureen E. Long
Standards Process Manager

September 20, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Recirculation Ballot Window Opens

The Standards Committee (SC) announces the following:

Recirculation Ballot Window for the Interpretation of BAL-003-0 Requirements R2, R2.2, R5, and R5.1 Opens September 20, 2007

The Electric Reliability Council of Texas (ERCOT) submitted a Request for an Interpretation of BAL-003-0 — Frequency Response and Bias Requirements R2, R2.2, R5, and R5.1. The request asked if there was a conflict between Requirement R2, which allows use of a variable bias setting, and Requirement R5, which does not specifically address the use of a variable bias setting.

The Interpretation clarifies that in reliability standard BAL-003-0, Requirements R2 and R5 do not conflict with one another. All members of the ballot pool are encouraged to review the comments submitted with the initial ballots, and the drafting team's responses to those comments.

The recirculation ballot for the Interpretation of BAL-003 Requirements R2, R2.2, R5, and R5.1 is open and will close at 8 p.m. (EDT) on Saturday, September 29, 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.

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

October 1, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement of Final Ballot Results

The Standards Committee (SC) announces the following:

Final Ballot Results for Interpretation of BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5, and R5.1

The recirculation ballot for the interpretation of BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5 and R5.1 was conducted from September 20–29, 2007 and the ballot passed. (Detailed Ballot Results)

The Electric Reliability Council of Texas (ERCOT) submitted a Request for an Interpretation of BAL-003-0 — Frequency Response and Bias Requirements R2, R2.2, R5, and R5.1. The request asked if there was a conflict between Requirement R2, which allows use of a variable bias setting, and Requirement R5, which does not specifically address the use of a variable bias setting.

Quorum: 85.90 %
Approval: 96.26 %

The Interpretation clarifies that in reliability standard BAL-003-0, Requirements R2 and R5 do not conflict with one another.

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 - BAL-003 - ERCOT_rc
Ballot Period:	9/20/2007 - 9/29/2007
Ballot Type:	recirculation
Total # Votes:	134
Total Ballot Pool:	156
Quorum:	**85.90 % The Quorum has been reached**
Weighted Segment Vote:	96.26 %
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.	42	1	25	1	0	0	13	4
2 - Segment 2.	10	0.8	8	0.8	0	0	1	1
3 - Segment 3.	36	1	28	1	0	0	4	4
4 - Segment 4.	10	0.5	5	0.5	0	0	1	4
5 - Segment 5.	24	1	16	1	0	0	2	6
6 - Segment 6.	18	1	11	0.846	2	0.154	3	2
7 - Segment 7.	1	0.1	1	0.1	0	0	0	0
8 - Segment 8.	3	0.2	1	0.1	1	0.1	0	1
9 - Segment 9.	7	0.7	7	0.7	0	0	0	0
10 - Segment 10.	5	0.5	5	0.5	0	0	0	0
Totals	**156**	**6.8**	**107**	**6.546**	**3**	**0.254**	**24**	**22**

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	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Duke Energy	Doug Hils		
1	East Kentucky Power Coop.	George S. Carruba		
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Power & Light Co.	C. Martin Mennes	Abstain	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	

1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
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	Manitoba Hydro	Robert G. Coish	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Abstain	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Abstain	
1	New York Power Authority	Ralph Rufrano	Abstain	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Joseph Dobes	Abstain	
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	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		
1	Sacramento Municipal Utility District	Dilip Mahendra	Abstain	View
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	Southern California Edison Co.	Dana Cabbell	Abstain	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Coop., Inc.	Alan H. Wilkinson	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association Inc.	Bruce A Sembrick	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Robert Temple	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper		
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Affirmative	
2	Independent Electricity System Operator	Don Tench	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Abstain	
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	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Burbank Water and Power	Xavier G. Baldwin	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	Abstain	
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 & Light Co.	W.R. Schoneck	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Gulf Power Company	William F. Pope	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Abstain	
3	JEA	Garry Baker		
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	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		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Cynthia Herron	Affirmative	
3	Tri-State G & T Association Inc.	Dillwyn H. Ramsay	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Consumers Energy Co.	David Frank Ronk	Affirmative	
4	Florida Municipal Power Agency	William S. May	Affirmative	
4	LaGen	Richard Comeaux		
4	LaGen	Keith Comeaux		
4	LaGen	Richard Comeaux		
4	LaGen	Keith Comeaux		
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 2 of Grant County	Kevin J. Conway	Abstain	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Alabama Electric Coop. Inc.	Tim Hattaway	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin		
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus		
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	East Kentucky Power Coop.	Gerard Bordes		
5	Florida Municipal Power Agency	Douglas Keegan	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	New York Power Authority	Richard J. Ardolino	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Abstain	

5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Southeastern Power Administration	Douglas Spencer		
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	Xcel Energy, Inc.	Stephen J. Beuning	Affirmative	
6	AEP Service Corp.	Dana E. Horton	Affirmative	
6	Entergy Services, Inc.	William Franklin	Negative	View
6	First Energy Solutions	Alfred G. Roth	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Abstain	
6	Powerex Corp.	Daniel W. O'Hearn	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
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	Tennessee Valley Authority	Katherine E. York	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Eastman Chemical Company	Lloyd Webb	Affirmative	
8	Energy Mark, Inc.	Howard F. Illian		
8	JDRJC Associates	Jim D. Cyrulewski	Negative	View
8	Other	Michehl R. Gent	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maryland Public Service Commission	James Schafer	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher	Affirmative	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	SERC Reliability Corporation	Gerry W. Cauley	Affirmative	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Approved by Stakeholders: September 29, 2007

Approved by NERC Board of Trustees: October 23, 2007

Interpretation of BAL-003-0 — Frequency Response and Bias, Requirements R2, R2.2, R5, and R5.1

Request for Interpretation received from ERCOT on May 31, 2007:

ERCOT specifically requests clarification that a Balancing Authority is entitled to use a variable bias value as authorized by Requirement R2.2, even though Requirement 5 seems not to account for the possibility of variable bias settings

Interpretation provided by NERC Resources Subcommittee on July 25, 2007:

The consensus of the Resources Subcommittee is that BAL-003-0 — Frequency Response and Bias — Requirement R2 does not conflict with BAL-003-0 Requirement R5.

BAL-003-0 — Frequency Response and Bias Requirement 2 requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting. The Balancing Authority may then choose a fixed bias (constant through the year) per Requirement 2.1, or a variable bias (varies with load, specific generators, etc.) per Requirement 2.2.

BAL-003-0

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.

BAL-003-0 — Frequency Response and Bias Requirement 5 sets a minimum contribution for all Balancing Authorities toward stabilizing interconnection frequency. The 1% bias setting establishes a minimum level of automatic generation control action to help stabilize frequency following a disturbance. By setting a floor on bias, Requirement 5 also helps ensure a consistent measure of control performance among all Balancing Authorities within a multi-Balancing Authority interconnection. However, ERCOT is a single Balancing Authority interconnection. The bias settings ERCOT uses do produce, on average, the best level of automatic generation control action to meet control performance metrics. The bias value in a single Balancing Authority interconnection does not impact the measure of control performance.

BAL-003-0

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.

A. Introduction

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

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

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.

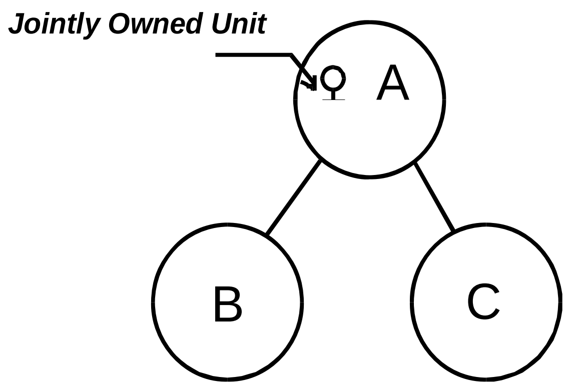
R2.2. The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such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

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

2. Appendix 2 – Interpretation of Requirements R2, R2.2, R5, and R5.1 (February 12, 2008).

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	Addition

0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial.	Errata
0a	February 12, 2008	Added Appendix 2 – Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition

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:

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

Appendix 2

Interpretation of Requirements R2, R2.2, R5, R5.1

Request: *ERCOT specifically requests clarification that a Balancing Authority is entitled to use a variable bias value as authorized by Requirement R2.2, even though Requirement 5 seems not to account for the possibility of variable bias settings.*

Interpretation:

The consensus of the Resources Subcommittee is that BAL-003-0 — Frequency Response and Bias — Requirement R2 does not conflict with BAL-003-0 Requirement R5.

BAL-003-0 — Frequency Response and Bias Requirement 2 requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting. The Balancing Authority may then choose a fixed bias (constant through the year) per Requirement 2.1, or a variable bias (varies with load, specific generators, etc.) per Requirement 2.2.

BAL-003-0

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.

BAL-003-0 — Frequency Response and Bias Requirement 5 sets a minimum contribution for all Balancing Authorities toward stabilizing interconnection frequency. The 1% bias setting establishes a minimum level of automatic generation control action to help stabilize frequency following a disturbance. By setting a floor on bias, Requirement 5 also helps ensure a consistent measure of control performance among all Balancing Authorities within a multi-Balancing Authority interconnection. However, ERCOT is a single Balancing Authority interconnection. The bias settings ERCOT uses do produce, on average, the best level of automatic generation control action to meet control performance metrics. The bias value in a single Balancing Authority interconnection does not impact the measure of control performance.

BAL-003-0

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.

Exhibit B-3

The complete development record of the formal interpretation

VAR-001-1 — Voltage and Reactive Control, Requirement R4

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Project 2007-28
Interpretation
VAR-001-1 - Voltage and Reactive Control

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

Status
Approved by Board of Trustees March 26, 2008. Pending regulatory approval.

The Dynegy Inc. interpretation request of NERC reliability standards VAR-001-1, Requirement 4 was approved by stakeholders on January 23, 2008.

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
Posted for Board of Trustees Approval on March 28, 2008 Interpretation (Same as #1) VAR-001-1, Requirement 4				
Announcement (8) Interpretation (Same as #1) VAR-001-1, Requirement 4 Posted for 10-day Recirculation Ballot Window		January 14–January 23, 2008 (closed)		Announcement (9) Recirculation Ballot Summary (10)
Announcement (4)	Dynegy	12/04/07 - 12/13/07		Announcement (5)

Interpretation (Same as #1) VAR-001-1, Requirement 4 Posted for 10-day Ballot Window	Request for Interpretation (Same as #2) VAR-001-1, R4	(closed) 10-day Ballot Window		Initial Ballot Summary (6) Consideration of Comments (7)
Announcement (2) Interpretation (1) VAR-001-1, Requirement 4 Posted for 30-day Pre-Ballot Review	Dynegy Request for Interpretation (3) VAR-001-1, R4	11/05/07 - 12/04/07 Pre-ballot Review (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.

Interpretation of NERC Standard VAR-001-1 — Voltage and Reactive Control, Requirement R4

Request for Interpretation received from Dynegy on October 11, 2007:

The current wording of VAR-001-1 Requirement 4 does not impose any explicit obligations on the Transmission Operator other than to provide the Generator Operator with a voltage or reactive power output schedule and an associated tolerance band.

1. *Is the Transmission Operator implicitly required to have a technical basis for specifying the voltage or reactive power and associated tolerance band?*
2. *Is the Transmission Operator implicitly required to issue a voltage or reactive power schedule and associated tolerance band that is reasonable and practical for the Generator Operator to maintain?*
3. *What measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band?*

VAR-001-1

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule[1] 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).

1 The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

Interpretation provided by members of the Phase III & IV Standard Drafting Team on October 30, 2007:

NERC Reliability Standard VAR-001-1 is only comprised of stated requirements and associated compliance elements. The requirements have been developed in a fair and open process, balloted and accepted by FERC for compliance review. Any “implicit” requirement would be based on subjective interpretation and viewpoint and therefore cannot be objectively measured and enforced. Any attempt at “interpreting an implicit requirement” would effectively be adding a new requirement to the standard. This can only be done through the SAR process.

Since there are no requirements in VAR-001-1 to issue a “technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band”, there are no measures or associated compliance elements in the standard.

The standard only requires that “Each Transmission Operator shall specify a voltage or Reactive Power schedule ….” and that “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….". Also, Measure 1 and the associated compliance elements follow accordingly by stating that "The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule …"

VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules

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.

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.

Requirement 2 and Requirement 2.2 of VAR-002-1 relate somewhat to questions #2 and 3. R2 states that "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." R2.2 goes on to state "When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met."

Maureen E. Long
Standards Process Manager

November 5, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement:
Three Pre-ballot Windows and Ballot Pools for Interpretations
Open November 5, 2007

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

Pre-ballot Window and Ballot Pool for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren Both Open November 5, 2007

Ameren submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1. The request also asked if TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 require that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 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_TPL_Ameren_in@ner.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 2007.

Pre-ballot Window and Ballot Pool for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO Both Open November 5, 2007

MISO submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asked if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios.

The request also asked if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 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_TPL_MISO_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 2007.

Pre-ballot Window and Ballot Pool for Interpretation of VAR-001-0 Requirement R4 for Dynegy Both Open November 5, 2007

Dynegy submitted a Request for an Interpretation of VAR-001-1 Requirement R4.

The request asked if the Transmission Operator is implicitly required to have a technical basis for specifying the voltage or reactive power schedule, asked if the voltage or reactive power schedule must be reasonable and practical for the Generator Operator to maintain, and asked what measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical voltage or reactive power schedule.

The Interpretation clarifies that VAR-001-1 is only comprised of stated requirements and associated measures and compliance elements. Interpreting an 'implicit' requirement would effectively be adding a new requirement to the standard and needs to be achieved with a Standard Authorization Request (SAR) to modify the standard rather than through an Interpretation. There are no requirements in VAR-001-1 to issue a "technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band."

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 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_VAR_Dynegy_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 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

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www.dynegy.com

DYNEGY

October 11, 2007

Maureen E. Long
Standards Process Manager
North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, New Jersey 08540-5721

Subject: Request for Interpretation of NERC Reliability Standard VAR-001-1

Dear Ms. Long:

Dynegy Inc. (Dynegy) is requesting an interpretation of Requirement 4 of North American Electric Reliability Corporation (NERC) Reliability Standard VAR-001-1. As a registered Generator Operator, Dynegy is directly impacted by this requirement. Dynegy is submitting this request for interpretation under the guidelines set out in "Interpretations of Standards" under the "Special Procedures" Section of Version 6.1 of the NERC Reliability Standards Development Procedure.

Background

Requirement 4 of NERC Reliability Standard VAR-001-1 provides as follows:

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule[1] 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).

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[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

NERC Reliability Standard VAR-002-1 is the companion standard to NERC Reliability Standard VAR-001-1. Requirement R2 and Measure M2 of Standard VAR-002-1 require the Generator Operator to control its voltage or reactive output to meet the voltage or Reactive Power schedule provided by its Transmission Operator. Section D.2.1.2 of the "Levels of Non-Compliance for Generator Operator" section of Standard VAR-002-1 defines one incident of failing to maintain a voltage or reactive power schedule as a non-compliance with R2 of Standard VAR-002-1.

Therefore, to be in compliance with R2 of NERC Reliability Standard VAR-002-1, Generator Operators must maintain the voltage or Reactive Power output within the tolerance band specified by the Transmission Operator (in accordance with R4 of Standard VAR-001-1) at *all* times.

Request for Interpretation Questions

The current wording of Requirement 4 of NERC Reliability Standard VAR-001-1 does not impose any explicit obligations on the Transmission Operator other than to provide the Generator Operator with a voltage or reactive power output schedule and an associated tolerance band.

Dynegy believes that Requirement R4 of NERC Reliability Standard VAR-001-1 requires interpretation. The specific questions that need to be answered are the following:

1. Is the Transmission Operator implicitly required to have a technical basis for specifying the voltage or reactive power schedule and associated tolerance band?

2. Is the Transmission Operator implicitly required to issue a voltage or reactive power schedule and associated tolerance band that is reasonable and practical for the Generator Operator to maintain?

3. What measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band?

Possible Interpretation and Material Impact of Misinterpretation

Question 1

The NERC Reliability Standards are intended to provide for the reliable operation of the bulk power system. Section 301 of the NERC Rules of Procedure states that reliability standards shall be "technically excellent." In addition, Section 302.5 of the NERC Rules of Procedure also requires that each reliability standard shall be based on "sound engineering and operating judgment, analysis, or experience…." For a Standard to comply with these characteristics, it must not only be drafted to reflect the requirements of Sections 301 and 302.5, it must also be implemented on that basis. Therefore, for a Transmission Operator to be in compliance with NERC Rules of Procedure, it must be required to have a technical basis for the specified voltage or reactive power schedule and associated tolerance band. In addition, Generator Operator compliance with the specified schedule and reliable system operation will likely be improved if the Generator Operator understands the basis for the schedule. This understanding can be achieved by requiring the Transmission Operator to share, upon request, the technical basis for the specified voltage or reactive power schedule and associate tolerance band with Generator Operators directly impacted by the Transmission Operator's specified schedule.

If the Transmission Operator is not required to have a technical basis for the specified voltage or reactive power schedule and associated tolerance band, the implementation of Standard VAR-001-1 by the Transmission Operator would violate the above provisions of the NERC Rules of Procedure. In addition, without a technical basis for the voltage or reactive power schedule and associated tolerance band, arbitrary target voltage values and arbitrary and either overly narrow or overly wide tolerance bands could be issued.

Either of these situations would potentially reduce system reliability. If the tolerance band is too narrow, the Generator Operator would be forced to spend an inordinate amount of time monitoring and reacting to numerous short term variations in voltage that do not present a threat to system reliability. This type of monitoring to simply avoid "non-compliances" with Standard VAR-002-1 would harm system reliability because plant personnel would be distracted from monitoring more critical plant operational parameters that have a much greater impact on system reliability. Furthermore, the Generator Operator's real time obligation to respond to any voltage or reactive directives from the Transmission Operator mitigates the need for this type of extraordinary monitoring by plant personnel to try to make sure the voltage is maintained within an overly narrow tolerance band. On the other hand, if the tolerance band is too wide, voltage levels on the system could jeopardize system reliability during system disturbances.

Question 2

Section 301 of the NERC Rules of Procedure states that reliability standards shall be "reasonable." In addition, Section 302.9 of the NERC Rules of Procedure states that "[e]ach reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities...." For a Standard to comply with these characteristics, it must not only be drafted to reflect these obligations, it must also be implemented in that same manner. Therefore, the Transmission Operator should be required to issue a voltage schedule (target voltage and associated tolerance band) or reactive power schedule that is reasonable and practical to maintain and allows the Generator Operator to operate in compliance with Requirement R2 of Standard VAR-002-1. For example, the tolerance band specified must take into account the inherent inaccuracy of the equipment that measures and converts voltage. In addition, because Requirement R2 of Standard VAR-002-1 essentially requires the Generator Operator to maintain the voltage within the specified tolerance band at all times, the tolerance band needs to be wide enough to allow the Generator Operator to practically operate within the tolerance band.

If the Transmission Operator is not required to issue a voltage schedule (target voltage and tolerance band) or reactive power schedule that is reasonable and practical for the Generator Operator to maintain, the implementation of Standard VAR-001-1 by the Transmission Operator would violate the above cited provisions of the NERC Rules of Procedure. For example, overly narrow tolerance bands could be partially or totally "eaten up" by the "instrument repeatability" error of the equipment used to measure voltage (*i.e.*, potential transformers, capacitor coupling voltage transformers, transducers), leaving little or no margin within the tolerance band to respond to system voltage variations. Unreasonable or impractical voltage or reactive power schedules would essentially force Generator Operators to incur artificially imposed violations of Requirement R2 of Standard VAR-002-1 and any associated penalties. This result would be in violation of Section 303 of the NERC Rules of Procedure which requires that standards be "developed with due consideration of impacts on competition, to ensure standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy…." In the absence of a voltage or reactive power schedule and associated tolerance band that is reasonable and practical, Transmission Operators will effectively impose on Generator Operators the cost of violations, thereby establishing an "unduly discriminatory" practice and material impacts on Generator Operators and competition.

<u>Question 3</u>

If a Transmission Operator is required to issue a technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band, Section 302.4 of the NERC Rules of Procedure states that "[e]ach performance requirement shall have one or more associated measures used to objectively evaluate compliance with the requirement." Therefore, a measure needs to be developed to establish the basis for an objective evaluation to determine if a technically based, reasonable and practical voltage or reactive power schedule was issued by the Transmission Operator.

This measure should state that the voltage or reactive power schedule and associated tolerance band issued by the Transmission Operator must either be (1) consistent with the historical variation of system voltage normalized to eliminate abnormal voltage fluctuations such as those caused by system disturbances or (2) consistent with the variation of system voltage when the plant/unit is not operating normalized to eliminate abnormal voltage fluctuations such as those caused by system disturbances If the specified voltage or reactive power schedule and associated tolerance band is not consistent with either of these provisions, the measure should require the Transmission Operator to have a technical study or analysis that justifies a different voltage or reactive power schedule and associated tolerance band.

If this type of measure is not explicitly stated, the Regional Entity will not have any objective method for judging if the Transmission Operator issued a technically based, reasonable and practical voltage or reactive power schedule and associated tolerance band in accordance with Requirement R4 of Standard VAR-001-1.

Dynegy appreciates the prompt attention of NERC to this standard interpretation request. If you have any questions regarding this request for interpretation, please let me know.

Sincerely,

Gregory A. Mason

Gregory A. Mason
Director – Reliability and Compliance
Dynegy Inc.
(217) 872 2301
gregory.a.mason@dynegy.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

December 4, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Three Initial Ballot Windows for Interpretations Open

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

Initial Ballot Window for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren Open until 8 p.m. (EST) December 13, 2007

Ameren submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1. The request also asked if TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 require that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

The initial ballot for the Interpretation (for Ameren) of TPL-002 and TPL-003 is open and will remain open until 8 p.m. (EST) on Thursday, December 13, 2007.

Initial Ballot Window for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO Open until 8 p.m. (EST) December 13, 2007

MISO submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asked if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios.

The request also asked if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

The initial ballot for the Interpretation (for MISO) of TPL-002 and TPL-003 is open and will remain open until 8 p.m. (EST) on Thursday, December 13, 2007.

Initial Ballot Window for Interpretation of VAR-001-0 Requirement R4 Open until 8 p.m. (EST) December 13, 2007

Dynegy submitted a Request for an Interpretation of VAR-001-1 — Voltage and Reactive Control, Requirement R4.

The request asked if the Transmission Operator is implicitly required to have a technical basis for specifying the voltage or reactive power schedule, asked if the voltage or reactive power schedule must be reasonable and practical for the Generator Operator to maintain, and asked what measure should be used to determine if the Transmission Operator has issued a technically based, reasonable, and practical voltage or reactive power schedule.

The Interpretation clarifies that VAR-001-1 is only comprised of stated requirements and associated measures and compliance elements. Interpreting an 'implicit' requirement would effectively be adding a new requirement to the standard and needs to be achieved with a Standard Authorization Request (SAR) to modify the standard rather than through an Interpretation. There are no requirements in VAR-001-1 to issue a "technically based, reasonable, and practical to maintain voltage or reactive power schedule and associated tolerance band."

The initial ballot for the Interpretation (for Dynegy) of VAR-001 is open and will remain open until 8 p.m. (EST) on Thursday, December 13, 2007.

Standards Development Process

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

Sincerely,

Maureen E. Long

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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

December 14, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement of Initial Ballot Results for Three Interpretations

The Standards Committee (SC) announces the following:

Initial Ballot Results for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren

The initial ballot for the Interpretation (for Ameren) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements was conducted from December 4–13, 2007.

The request for interpretation asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1. The request also asked if TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 require that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to 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:	86.70 %
Approval:	88.10 %

Initial Ballot Results for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO

The initial ballot for the Interpretation (for MISO) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, was conducted from December 4–13, 2007.

The request for interpretation asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards. MISO then asked if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios. The request also asked if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

The ballot achieved a quorum, however there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to 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:	86.10 %
Approval:	87.50 %

Initial Ballot Results for Interpretation of VAR-001-0 Requirement R4 for Dynegy

The initial ballot for the Interpretation (for Dynegy) of VAR-001-0 — Voltage and Reactive Control, Requirement R4, was conducted from December 4–13, 2007.

The request for interpretation asked if the Transmission Operator is implicitly required to have a technical basis for specifying the voltage or reactive power schedule; asked if the voltage or reactive power schedule must be reasonable and practical for the Generator Operator to maintain; and asked what measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical voltage or reactive power schedule.

The Interpretation clarifies that VAR-001-1 is only comprised of the stated requirements and associated measures and compliance elements. Interpreting an "implicit" requirement would effectively be adding a new requirement to the standard and needs to be achieved with a Standard Authorization Request (SAR) to modify the standard rather than through an Interpretation. There are no requirements in VAR-001-1 to issue a "technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band."

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to 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:	86.41 %
Approval:	93.00 %

Standards Development Process

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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 VAR-001 - Dynegy_in
Ballot Period:	12/4/2007 - 12/13/2007
Ballot Type:	Initial
Total # Votes:	159
Total Ballot Pool:	184
Quorum:	**86.41 % The Quorum has been reached**
Weighted Segment Vote:	93.00 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	58	1	49	0.961	2	0.039	1	6
2 - Segment 2.	8	0.7	7	0.7	0	0	1	0
3 - Segment 3.	47	1	35	0.897	4	0.103	1	7
4 - Segment 4.	7	0.5	5	0.5	0	0	1	1
5 - Segment 5.	32	1	18	0.857	3	0.143	4	7
6 - Segment 6.	17	1	12	0.923	1	0.077	1	3
7 - Segment 7.	1	0.1	1	0.1	0	0	0	0
8 - Segment 8.	2	0.2	2	0.2	0	0	0	0
9 - Segment 9.	7	0.6	6	0.6	0	0	0	1
10 - Segment 10.	5	0.5	4	0.4	1	0.1	0	0
Totals	**184**	**6.6**	**139**	**6.138**	**11**	**0.462**	**9**	**25**

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	Ameren Services Company	Kirit S. Shah	Affirmative	
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Abstain	
1	Basin Electric Power Cooperative	David Rudolph	Negative	
1	Bonneville Power Administration	Donald S. Watkins		
1	CenterPoint Energy	Paul Rocha	Affirmative	
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	Affirmative	
1	Duke Energy Carolina	Doug Hils	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	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		
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	Lincoln Electric System	Doug Bantam		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Robert G. Coish	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	National Grid	Michael J Ranalli	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	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	Negative	
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		
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra		
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Mike Wech	Affirmative	
1	Tri-State G & T Association Inc.	Bruce A Sembrick	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Affirmative	
1	Western Area Power Administration	Robert Temple	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Electric Reliability Council of Texas,	Roy D. McCoy	Abstain	

	Inc.			
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	View
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	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl		
3	City of Tallahassee	Rusty S. Foster	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak	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 Carolina	Henry Ernst-Jr		
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	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	JEA	Garry Baker	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lincoln Electric System	Bruce Merrill	Negative	View
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Ronald Dacombe	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PECO Energy an Exelon Co.	John J. McCawley		
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. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron		
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Wisconsin Public Service Corp.	James A. Maenner	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	

4	American Municipal Power - Ohio	Chris Norton	Abstain	
4	Consumers Energy Co.	David Frank Ronk	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin		
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Abstain	
5	Colorado Springs Utilities	Patrick Daley		
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Negative	View
5	Dynegy	Greg Mason	Negative	
5	Entergy Corporation	Stanley M Jaskot		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	Douglas Keegan		
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	New York Power Authority	Richard J. Ardolino	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Negative	
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	Bonneville Power Administration	Brenda S. Anderson		
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	First Energy Solutions	Alfred G. Roth	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Manitoba Hydro	Daniel Prowse	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	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	

6	Southern Company Generation and Energy Marketing	J. Roman Carter	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
7	Eastman Chemical Company	Lloyd Webb	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Other	Michehl R. Gent	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher		
9	North Carolina Utilities Commission	Kimberly J. Jones	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
9	Wyoming Public Service Commission	Steve Oxley	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Negative	View
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	View

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

Consideration of Comments on Initial Ballot of Interpretation of VAR-001-1 — Voltage and Reactive Control, Requirement R4 for Dynegy

Summary Consideration: The drafting team did not make any changes to the interpretation based on stakeholder comments. Several commenters suggested that the interpretation process should not have been used to answer the question submitted. The Drafting Team believes that the interpretation process was properly followed. It also believes that the requestor should be given some insight into the rationale behind the response and related materials. Implied requirements are open to subjective interpretation without a firm basis and could lead to a variety of meanings. In this case, a SAR and the use of the approved open process is appropriate.

Voter	Entity	Segment	Vote	Comment
Terry Bilke	Midwest ISO, Inc.	2	Affirmative	We agree that the TOP should provide a technically sound set of limits and that the generator operator should be part of the process. However, the interpretation process should not be used to change or add to a standard.
Response: Thank you for your input. The Interpretation Team believes that the process was properly followed and the interpretation did not change or add to a standard.				
Bruce Merrill Eric Ruskamp	Lincoln Electric System	3 6	Negative	LES agrees with the Interpretation, however, this once again appears to be an unnecessary Interpretation. Dynegy expresses some potential concerns, but these would be better addressed in a SAR rather than an Interpretation. NERC should use some discretion in issuing Interpretations as the current volume of Interpretations is troubling. A formal Interpretation should not be needed to answer "is X a requirement of this standard". Additionally, Dynegy simplified their Interpretation Request into three questions. These three questions could have been addressed in a simplified manner making the Interpretation easier to understand. Suggested answers to Dynegy's questions: 1. No, this is not a Requirement of this standard. 2. No, this is not a Requirement of this standard. 3. The Measures are based on the Requirements, and this is not a Requirement of this standard. If Dynegy feels changes need made to the current standard the SDT recommends pursuing a SAR.
Response: Thank you for your input. The Interpretation Team believes that the process was properly followed. It also believes that the requestor should be given some insight into the rationale behind the response and related materials.				

James A. Maenner	Wisconsin Public Service Corp.	3	Negative	WPSC/UPPCo agrees with the Interpretation, however, this appears to be an unnecessary Interpretation. Dynegy expresses some potential concerns, but these would be better addressed in a SAR rather than an Interpretation. NERC should use some discretion in issuing Interpretations; a formal Interpretation should not be necessary to answer whether a requirement is part of a standard.
Response: Thank you for your input. The Interpretation Team believes that the process was properly followed. It also believes that the requestor should be given some insight into the rationale behind the response and related materials.				
Ronald W. Bauer	Detroit Edison Company	5	Negative	We disagree with the interpretation. Actions taken by any entity to comply with specific NERC Standard requirements should always be consistent with good utility practices. R1 of VAR-001-1 requires "...that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels.." Therefore Transmission Owners should be expected to have clear procedures in place in how it controls voltage levels. Therefore, in our opinion, when the Transmission owner specifies a Reactive Power schedule it is implied that it is reasonable and practical for the Generator to maintain.
Response: Thank you for your input. As the commenter states “it is implied” and not a stated requirement that can be objectively measured. Implied requirements are open to subjective interpretation without a firm basis and could lead to a variety of meanings. In this case, a SAR and the use of the approved open process is appropriate.				
Larry Brusseau	Midwest Reliability Organization	10	Negative	The MRO agrees with the Interpretation, however, this once again appears to be an unnecessary Interpretation. Dynegy expresses some potential concerns, but these would be better addressed in a SAR rather than an Interpretation. NERC should use some discretion in issuing Interpretations as the current volume of Interpretations is troubling. A formal Interpretation should not be needed to answer "is X a requirement of this standard". Additionally, Dynegy simplified their Interpretation Request into three questions. These three questions could have been addressed in a simplified manner making the Interpretation easier to understand. Suggested answers to Dynegy's questions: 1. No, this is not a Requirement of this standard. 2. No, this is not a Requirement of this standard. 3. The Measures are based on the Requirements and this is not a Requirement of this standard. If Dynegy feels changes need to be made to the current standard, MRO recommends pursuing a SAR.
Response: Thank you for your input. The Interpretation Team believes that the process was properly followed. It also believes that the requestor should be given some insight into the rationale behind the response and related materials.				
Charles H. Yeung	Southwest Power Pool	10	Affirmative	NERC should consider other possible ways to respond to such questions. A more interactive approach may be more helpful to this requestor since the requirement(s) they seek do not exist in the current NERC standards. Discussion at a NERC committee or a web-based forum may have sufficed.
Response: Thank you for you input. If asked for an informal response to a question about a standard, NERC will provide an informal response.				

Standards Announcement:
Recirculation Ballot Window Opens
January 14, 2008

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

The Standards Committee (SC) announces the following:

Recirculation Ballot Window for Interpretation of VAR-001-0 Requirement R4 (for Dynegy) is Open

The recirculation ballot for the Interpretation of R4 in VAR-001-1 — Voltage and Reactive Control requested by Dynegy is open through 8 p.m. (EST) on Wednesday, January 23, 2007. The Standards Committee encourages all members of the Ballot Pool to review the consideration of initial ballot comments.

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 a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot.

Recirculation Ballot Window for Revised Interpretation of BAL-005-1 Requirement R17 (for PGE) is Open

The recirculation ballot for the Revised Interpretation of R17 inBal-005-1 — Automatic Generation Control requested by Portland General Electric is open through 8 p.m. (EST) on Wednesday, January 23, 2007. The Standards Committee encourages all members of the Ballot Pool to review the consideration of initial ballot comments.

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 a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot.

Standards Development Process

The NERC posting and balloting procedures are described in the *Reliability Standards Development Procedure Manual*, which 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.

Please send questions to Maureen Long at maureen.long@nerc.net, or call 813-468-5998.

Sincerely,

Maureen E. Long

Maureen Long
Standards Process Manager
maureen.long@nerc.net
813-468-5998

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

Maureen E. Long
Standards Process Manager

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

January 25, 2007

Re: Final Ballot Results

The Standards Committee (SC) announces the following:

Final Ballot Results for Interpretation of BAL-005-1 — Automatic Generation Control, Requirement 17
The recirculation ballot for the revised interpretation of BAL-005-1 — Automatic Generation Control, Requirement 17 for Portland General Electric Company was conducted from January 14 –23, 2008 and the ballot passed. (Detailed Ballot Results)

Quorum: 87.65 %
Approval: 98.17 %

The Interpretation clarifies that in reliability standard BAL-005-1, Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the area control error (ACE) equation or provide real-time time error or frequency information to the system operator. The requirement does not apply to frequency inputs from other sources that are for reference only. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the balancing authority; however, the balancing authority has the responsibility for the accuracy of the frequency and time error measurement devices.

This interpretation for Portland General Electric Company expands on the previous interpretation of BAL-005-1 Requirement 17 developed for R.W. Beck that was approved by the Board of Trustees on May 2, 2007. If the Board of Trustees approves the interpretation for Portland General Electric, the interpretation for R.W. Beck will be retired.

Final Ballot Results for Interpretation of VAR-001-1 — Voltage and Reactive Control, Requirement 4
The recirculation ballot for the interpretation of VAR-001-1 — Voltage and Reactive Control, Requirement 4 for Dynegy was conducted from January 14–23, 2008 and the ballot passed. (Detailed Ballot Results)

Quorum: 89.67 %
Approval: 93.18 %

The Interpretation clarifies that VAR-001-1, Requirement 4 does not include any language regarding the "quality" of the transmission operator's voltage or reactive power schedule.

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.

Reliability Standards

Ballot Results	
Ballot Name:	Interpretation Request for VAR-001 - Dynegy_rc
Ballot Period:	1/14/2008 - 1/23/2008
Ballot Type:	recirculation
Total # Votes:	165
Total Ballot Pool:	184
Quorum:	**89.67 % The Quorum has been reached**
Weighted Segment Vote:	93.18 %
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.	58	1	49	0.961	2	0.039	3	4
2 - Segment 2.	8	0.7	7	0.7	0	0	1	0
3 - Segment 3.	47	1	37	0.902	4	0.098	1	5
4 - Segment 4.	7	0.6	6	0.6	0	0	1	0
5 - Segment 5.	32	1	19	0.864	3	0.136	4	6
6 - Segment 6.	17	1	12	0.923	1	0.077	1	3
7 - Segment 7.	1	0.1	1	0.1	0	0	0	0
8 - Segment 8.	2	0.2	2	0.2	0	0	0	0
9 - Segment 9.	7	0.5	5	0.5	0	0	1	1
10 - Segment 10.	5	0.5	4	0.4	1	0.1	0	0
Totals	**184**	**6.6**	**142**	**6.15**	**11**	**0.45**	**12**	**19**

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	Ameren Services Company	Kirit S. Shah	Affirmative	
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Abstain	
1	Basin Electric Power Cooperative	David Rudolph	Negative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
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	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	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	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	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Robert G. Coish	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	National Grid	Michael J Ranalli	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Abstain	
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	Negative	
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		
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra		
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
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2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Electric Reliability Council of Texas,	Roy D. McCoy	Abstain	

	Inc.			
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	View
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3	Allegheny Power	Bob Reeping	Affirmative	
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5	Avista Corp.	Edward F. Groce	Abstain	
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	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Abstain	
5	Colorado Springs Utilities	Patrick Daley		
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Negative	View
5	Dynegy	Greg Mason	Negative	
5	Entergy Corporation	Stanley M Jaskot		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	Douglas Keegan		
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	New York Power Authority	Richard J. Ardolino	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Negative	
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	Bonneville Power Administration	Brenda S. Anderson		
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	First Energy Solutions	Alfred G. Roth	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Manitoba Hydro	Daniel Prowse	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	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	

6	Southern Company Generation and Energy Marketing	J. Roman Carter	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
7	Eastman Chemical Company	Lloyd Webb	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Other	Michehl R. Gent	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher		
9	North Carolina Utilities Commission	Kimberly J. Jones	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Abstain	
9	Wyoming Public Service Commission	Steve Oxley	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Negative	View
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	View

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A. Introduction

1. **Title:** **Voltage and Reactive Control**

2. **Number:** VAR-001-1

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Purchasing-Selling Entities.

5. **Effective Date:** Six months after BOT adoption.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

R3.1. Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.

R3.2. For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] 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).

R5. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

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 Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

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

1.4. Additional Compliance Information

The Transmission Operator shall 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

2.1. Level 1: No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2

2.2. Level 2: There shall be a level two non-compliance if either of the following conditions exists:

2.2.1 No evidence to show that directives were issued in accordance with R6.1.

2.2.2 No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with R11.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions exists:

2.3.1 Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.

2.4. Level 4: No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1a	March 26, 2008	Added Appendix 1 – Interpretation of R4 approved by BOT on March 26, 2008.	Revised

Appendix 1

Interpretation of Requirement 4

Request:

The current wording of VAR-001-1 Requirement 4 does not impose any explicit obligations on the Transmission Operator other than to provide the Generator Operator with a voltage or reactive power output schedule and an associated tolerance band.

1. *Is the Transmission Operator implicitly required to have a technical basis for specifying the voltage or reactive power and associated tolerance band?*
2. *Is the Transmission Operator implicitly required to issue a voltage or reactive power schedule and associated tolerance band that is reasonable and practical for the Generator Operator to maintain?*
3. *What measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band?*

VAR-001-1

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule[1] 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).

[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

Interpretation:

NERC Reliability Standard VAR-001-1 is only comprised of stated requirements and associated compliance elements. The requirements have been developed in a fair and open process, balloted and accepted by FERC for compliance review. Any "implicit" requirement would be based on subjective interpretation and viewpoint and therefore cannot be objectively measured and enforced. Any attempt at "interpreting an implicit requirement" would effectively be adding a new requirement to the standard. This can only be done through the SAR process.

Since there are no requirements in VAR-001-1 to issue a "technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band", there are no measures or associated compliance elements in the standard.

The standard only requires that "Each Transmission Operator shall specify a voltage or Reactive Power schedule …." and that "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….". Also, Measure 1 and the associated compliance elements follow accordingly by stating that "The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule …"

VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules

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.

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.

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