NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

December 8, 2009

<u>VIA ELECTRONIC FILING</u>

David Erickson
President and Chief Executive Officer
Alberta Electric System Operator
2500, 330 – 5 Avenue SW
Calgary, Alberta
T2P 0L4

Re: *North American Electric Reliability Corporation*

Dear Mr. Erickson:

The North American Electric Reliability Corporation ("NERC") hereby submits this Notice of Filing of interpretations of Requirement R3 in NERC Reliability Standard TOP-005-1.1 — Operational Reliability Information, and Requirement R12 of NERC Reliability Standard IRO-005-2 — Reliability Coordination - Current Day Operations set forth in **Exhibit A** to this notice. The standards that include the interpretations will be referred to as TOP-005-1.1a and IRO-005-2a, respectively.

The interpretations were approved by the NERC Board of Trustees on November 5, 2009.

NERC's notice consists of the following:

- This transmittal letter;
- A table of contents for the filing;
- A narrative description explaining how the interpretation meets the reliability goals of the standards involved;
- Interpretation of TOP-005-1.1, Requirement R3 (**Exhibit A**);
- Interpretation of IRO-005-2, Requirement 12 (**Exhibit A**);

- Reliability Standard TOP-005-1.1a — Operational Reliability Information that includes the appended interpretation (**Exhibit B**);
- Reliability Standard IRO-005-2a — Reliability Coordination - Current Day Operations that includes the Appended Interpretation (**Exhibit B**);
- The complete development record of the interpretations (**Exhibit C**); and
- A roster of the interpretation development team **(Exhibit D)**.

Please contact the undersigned if you have any questions.

Respectfully submitted,

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

BEFORE THE
ALBERTA ELECTRIC SYSTEM OPERATOR

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

NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF INTERPRETATIONS TO RELIABILITY STANDARD TOP-005-1.1 — OPERATIONAL RELIABILITY INFORMATION AND RELIABILITY STANDARD IRO-005-2 — RELIABILITY COORDINATION - CURRENT DAY OPERATIONS

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December 8, 2009

TABLE OF CONTENTS

I. INTRODUCTION

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

TOP-005-1.1[1] — Operational Reliability Information

IRO-005-2[2] — Reliability Coordination - Current Day Operations

No modification to the language contained in these specific standard requirements is being proposed through the interpretations. The NERC Board of Trustees approved the interpretations to TOP-005-1.1 — Operational Reliability Information, Requirement R3, and IRO-005-2 — Reliability Coordination - Current Day Operations, Requirement R12 on November 5, 2009. **Exhibit A** to this filing sets forth the interpretations. **Exhibit B** contains the affected Reliability Standards containing the appended interpretations. **Exhibit C** contains the complete development record of the interpretations to these Reliability Standard requirements. **Exhibit D** contains the interpretation development team roster.

NERC filed these interpretations with the Federal Energy Regulatory Commission ("FERC") on November 24, 2009, and is filing these interpretations with the other applicable governmental authorities in Canada.

[1] At the time the request for interpretation was submitted in November 2008, Version 1 of the TOP-005 standard was the only version in effect. The request was therefore processed referencing TOP-005-1. Since then, TOP-005-1.1 has been submitted. The changes in TOP-005-1.1 relative to Version 1 of TOP-005 are not material to the substance of the interpretation request under consideration. In this regard, NERC will append the interpretation to Version 1.1 of the TOP-005 standard in lieu of Version 1.

[2] At the time the request for interpretation was submitted in November 2008, Version 1 of the IRO-005 standard was the only version in effect. The request was therefore processed referencing IRO-005-1. Since then, IRO-005 Version 2 has been submitted. The changes to Requirement R12 in Version 2 relative to Version 1 of IRO-005 are not material to the substance of the interpretation request under consideration. In this regard, NERC will append the interpretation to Version 2 of the IRO-005 standard in lieu of Version 1.

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. Reliability Standards Development Procedure and Interpretations

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 a Reliability Standard, as discussed in NERC's *Reliability Standards Development Procedure,* which is incorporated into the Rules of Procedure as Appendix 3A.[3] Upon request, NERC will assemble a team with the relevant expertise to address the interpretation request and, within 45 days, present an interpretation for industry ballot. If approved by the ballot pool and the NERC Board of Trustees, the interpretation is appended to the Reliability Standard and filed for approval by the applicable governmental authorities to be made effective when approved. When the affected Reliability Standard is next revised using

[3] *See* NERC's *Reliability Standards Development Procedure*, Approved by the NERC Board of Trustees on March 12, 2007, and Effective June 7, 2007 ("*Reliability Standards Development Procedure*"), available at http://www.nerc.com/files/Appendix3A_StandardsDevelopmentProcess.pdf.

the *Reliability Standards Development Procedure*, the interpretation will then be incorporated into the Reliability Standard.

The interpretations set out in **Exhibit A** were developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure.* They were approved by the NERC Board of Trustees on November 5, 2009.

During its November 5, 2009 meeting, the NERC Board of Trustees offered guidance regarding interpretations and the interpretations process. As part of this guidance, the NERC Board of Trustees adopted the following resolution:

> WHEREAS, the NERC Board of Trustees has considered the record of development of a number of proposed interpretations of Reliability Standards, the discussion and recommendations from the November 4, 2009 conference on interpretations, and the recommendation of NERC management,
>
> RESOLVED, that the NERC Board of Trustees approves the following proposed interpretations of Reliability Standards:
>
> 1. Interpretation of Requirement R1 of PRC-005-1;
> 2. Interpretations of Requirement R3 of TOP-005-1 and Requirement R12 of IRO-005-1;
> 3. Interpretation of Requirement R2 of CIP-007-1;
> 4. Interpretation of Requirement R1.3.10 of TPL-002-0;
> 5. Interpretation of Requirements R2 and R8 of MOD-001-1; and Requirements R5 and R6 of MOD-029-1;
>
> FURTHER RESOLVED, that the NERC Board of Trustees provides the following guidance regarding interpretations and the interpretations process:
>
> a. In deciding whether or not to approve a proposed interpretation, the board will use a standard of strict construction and not seek to expand the reach of the standard to correct a perceived gap or deficiency in the standard;
>
> b. It is the expectation of the board that when work on an interpretation reveals a gap or deficiency in a Reliability Standard, stakeholders will take prompt action to address the gap or deficiency in the standard and that the time and effort expended on the interpretation should be a relatively small proportion of the time and effort expended on addressing the gap or deficiency;

c. Priority should be given to addressing deficiencies or gaps in standards that pose a significant risk to the reliability of the bulk power system — addressing the gaps and deficiencies identified in Reliability Standard PRC-005-1 should be given such priority, and the Standards Committee should report on its plans and progress in that regard at the board's February 2010 meeting;

d. The Standards Committee should ensure that the comments by NERC staff and other stakeholders on the proposed interpretations are considered by the standard drafting team in addressing any identified gaps and deficiencies, with a report back to the board on the disposition of those comments;

e. The number of registrants that might end up in non-compliance or the difficulty of compliance are not appropriate inputs to an interpretation process, although those inputs may well be appropriate considerations in a standard development process and development of an implementation plan; and

f. Requests for a decision on how a Reliability Standard applies to a registered entity's particular facts and circumstances should not be addressed through the interpretations process.

Therefore, the NERC Board of Trustees, in approving these interpretations, did so using a standard of strict construction that does not expand the reach of the standard or correct a perceived gap or deficiency in the standard. However, the NERC Board of Trustees recommended that any gaps or deficiencies in a Reliability Standard that are evident through the interpretation process be addressed promptly by the standard drafting team. NERC Staff has been so advised, and will further examine any gaps or deficiencies in Reliability Standards TOP-005-1.1a — Operational Reliability Information or IRO-005-2a — Reliability Coordination - Current Day Operations in its consideration of the next version of these standards through the *Reliability Standards Development Procedure*.

Reliability Standard TOP-005-1.1 addresses operating data that is required by various reliability entities in order to monitor system conditions within their area. Requirement R3 of TOP-005-1.1 obligates Balancing Authorities and Transmission Operators to provide the types of data listed in Attachment 1 of the Standard – ("Attachment 1 – TOP-005-1.1 Electric System Reliability Data"), to other Balancing Authorities and Transmission Operators unless otherwise agreed.

Reliability Standard IRO-005-2 Requirement R12 addresses the monitoring responsibilities of Reliability Coordinators and includes requirements for the exchange of information between Transmission Operators and their respective Reliability Coordinators concerning Special Protection Systems ("SPS").

In this filing, NERC is submitting proposed interpretations to Reliability Standards TOP-005-1.1— Operational Reliability Information, Requirement R3, and IRO-005-2 — Reliability Coordination - Current Day Operations, Requirement R12, which are found in **Exhibit B**. In Section IV (a) below, NERC discusses the interpretations, explains the need for, and discusses the development of, the interpretations to the referenced requirements. In this discussion, NERC demonstrates that the interpretations are consistent with the stated reliability goals of and the requirements thereunder. Set forth below in Section IV (b) are the stakeholder ballot results and an explanation of how stakeholder comments were considered and addressed by the interpretation development team assembled to provide the interpretation.

The complete development record for the interpretations is set forth in **Exhibit C**. **Exhibit C** includes the requests for the interpretations, the responses to the requests for interpretations, the ballot pool and the final ballot results by registered ballot body members, stakeholder comments received during the balloting and an explanation of how those comments were considered. **Exhibit D** contains the interpretation development team roster.

IV. JUSTIFICATION OF INTERPRETATIONS

On November 25, 2008, Manitoba Hydro requested an interpretation of the meaning of the term "degraded/degradation" as used in NERC Reliability Standards TOP-005-1 and IRO-005-1,[4] and asked specifically whether an SPS that is operating with only one communication channel in service would be considered "degraded" for the purposes of these standards. In the letter supporting the request, Manitoba Hydro offered:

> Unlike other facilities, Special Protection Systems are required by NERC standards to be designed with redundant communication channels, so that if one communication channel fails the SPS is able to remain in operation. Requirement R1.3 of NERC Standard PRC-012-0 requires a Regional Reliability Organization with Transmission Owners that use SPSs to have a documented review procedure to ensure that SPSs comply with reliability standards and criteria, including: "requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements in TPL-

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[4] In its request, Manitoba Hydro included PRC-012-0 as relevant to the inquiry but the standard is not directly subject to the interpretation and therefore will not be modified through this proposal. The relevant sections of PRC-012 are as follows:

> **Purpose:** To ensure that all SPS are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
>
> > **R1.** Each Regional Entity with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Entity SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:
> >
> > > **R1.3**. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001- 0, TPL-002-0, and TPL-003-0.

> 001-0, TPL-002-0 and TPL-003-0". Accordingly, SPSs are designed to continue to perform their function with only one communication channel in service."

The stated purposes of the standards under consideration and the associated requirement language are as follows:

> **TOP-005-1.1 —** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
>
>> **R3.** Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

Included in the types of data listed in Attachment 1 of TOP-005-1.1, item 2.6 are "[n]ew or degraded special protection systems."

> **IRO-005-2 —** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
>
>> **R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a [System Operating Limit ("SOL") or [Interconnection Reliability Operating Limit ("IROL")] violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

Development of the requested interpretation was assigned to subset of the Real-Time Operations drafting team whose scope includes the Transmission Operations family of NERC Reliability Standards. The response developed by the interpretation development team, approved by ballot of the NERC stakeholders, and approved by the NERC Board of Trustees, is:

> TOP-005-1 does not provide, nor does it require, a definition for the term "degraded."
>
> The IRO-005-2 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed; thus if the loss of a communication channel results in the failure of an SPS to operate as designed, then the Transmission Operator is required to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

NERC believes that the interpretation as presented directly supports the reliability purpose of the standard because it clarifies what is required to be reported for "degraded" conditions regarding SPS for which the Reliability Coordinator would need to be notified to maintain situation awareness. This interpretation will result in ensuring that an adequate level of reliability for the bulk power system will be achieved and maintained by providing clarity and certainty in support of this important reliability objective.

V. <u>SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS</u>

NERC presented the interpretation response for pre-ballot review on February 18, 2009 followed by an initial ballot that began on March 19, 2009. The interpretation achieved 92.62 percent weighted segment approval with 89.78 percent quorum participating. There were 14 negative ballots submitted for the initial ballot, and ten of those ballots included a comment. Some balloters listed more than one reason for their negative ballot. The reasons cited for the negative ballots included the following:

- Three balloters indicated a need for a definition of degraded so an entity can be evaluated on a known measurable basis. The balloters stated that since SPSs are designed so that no one component failure will prevent the SPS to operate as designed, there would be no requirement for the SPS unit to be reported for a single failure. The balloters state, however, that when an SPS alone is not operating as designed (*i.e.*, degraded), the SPS is not functional and should be removed from the BES.

- Two balloters disagreed with the drafting team's description of degradation. The balloters view degradation as an indication of the existence of a problem but not the state of failure; the balloters interpreted the drafting team's description of degradation as the state of failure.
- Two balloters indicated any off-nominal SPS operating states should be appropriately reported, regardless of how degradation is defined.
- One balloter indicated the interpretation extends to requirements associated but not included in the request, resulting in too broad an application of the interpretation process.
- One balloter agreed with the conclusion for IRO-005-1 but disagreed that a definition for degraded is not needed for TOP-005-1. The balloter suggested the Transmission Operator and Balancing Authority are obligated to provide information on new or degraded special protections systems to the Reliability Coordinator upon request, and a definition of degraded is necessary for specifying systems that would need to be reported.

In response to these comments, the interpretation development team responded that an interpretation does not permit the creation of requirements or definitions. Absent this ability to define "degraded," the team provided its subjective view of the intent of the word. In its view, the term "any degradation or potential failure to operate as expected" was interpreted to mean "any actual or any forecasted conditions that would result in the SPS not operating as expected." The team made no changes to the interpretation based on the comments offered.

The recirculation ballot was conducted from April 17, 2009 to April 27, 2009 and achieved a quorum of 95.56 percent with a weighted affirmative approval of 92.81 percent.

Respectfully submitted,

/s/ Holly A. Hawkins
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Exhibit A

Interpretations of Reliability Standards

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Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard
Date submitted: November 25, 2008
Contact information for person requesting the interpretation:
Name: K. Jennifer Moroz
Organization: Manitoba Hydro
Telephone: (204) 474-4539
E-mail: kjmoroz@hydro.mb.ca
Identify the standard that needs clarification:
TOP-005-1 — Operational Reliability Information IRO-005-1 — Reliability Coordination - Current Day Operations PRC-012-0 — Special Protection System Review Procedure
Identify specifically what needs clarification (If a category is not applicable, please leave it blank):
TOP-005-1 Requirement R3. **R3.** Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability. *The above-referenced Attachment 1 - TOP-005-0 specifies the following data as item 2.6:* 2.6. New or <u>degraded</u> special protection systems. *[Underline added for emphasis.]* **IRO-005-1 Requirement R12.** **R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any <u>degradation</u> or potential failure to operate as expected. *[Underline added for emphasis.]*

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PRC-012-0 Requirement R1 and R1.3: **R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:** **R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.** **Clarification needed** **See attached letter.**
Identify the material impact associated with this interpretation:
Noncompliance could result in penalties and sanctions.

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Manitoba Hydro

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November 25, 2008

The North American Electric Reliability Corporation
Princeton Forrestal Village
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PRINCETON, New Jersey
U.S.A. 08540-5731

ATTENTION: **Ms. Maureen E. Long , Standards Process Manager**

Dear Ms. Long:

RE: REQUEST FOR INTERPRETATION OF NERC STANDARDS TOP-005-1; IRO-005-1

Manitoba Hydro respectfully requests an interpretation of Reliability Standards TOP-005-1 and IRO-005-1 pursuant to Appendix 3A of the North American Electric Reliability Corporation's ("NERC") Rules of Procedure. As a Balancing Authority and an operator of transmission facilities that is bound by Manitoba law to adhere to NERC reliability standards, except as modified or disallowed by order of the government of Manitoba, Manitoba Hydro is directly and materially affected by the above-referenced standards. Accordingly, Manitoba Hydro is entitled to request NERC's interpretation of these standards, pursuant to Appendix 3A of the NERC Rules of Procedure.

Request

Manitoba Hydro requests an interpretation of the meaning of the term "degraded/degradation" as used in NERC Standards TOP-005-1 and IRO-005-1 and specifically, whether a Special Protection System that is operating with only one communication channel in service would be considered "degraded" for the purposes of these standards.

Standards To Be Interpreted

NERC Standard TOP-005-1 entitled "Operational Reliability Information" governs the operating data that is required by various reliability entities to monitor system conditions within their area. Requirement R3 of TOP-005-1 obligates Balancing Authorities and Transmission Operators to provide the types of data as listed in Attachment 1 - TOP-005-0 ("Electric System Reliability Data"), to other Balancing Authorities and Transmission Operators unless otherwise agreed. The above-referenced Attachment 1 - TOP-005-0 specifies the following data as item 2.6:

> "2.6 New or degraded special protection systems."

Similarly, NERC Standard IRO-005-1 entitled "Reliability Coordination - Current Day Operations", which governs the monitoring responsibilities of Reliability Coordinators, includes requirements for the exchange of information between Transmission Operators and their respective Reliability Coordinators concerning special protection systems. Requirement R12 of IRO-005-1 provides the following:

> "The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected."

Basis for Clarification

Manitoba Hydro respectfully requests that NERC clarify that a Special Protection System is not considered "degraded" for the purpose of the above-referenced NERC Standards if it is operating with one communication channel out of service. Manitoba Hydro considers this to be a reasonable interpretation for the following reasons.

Since the terms "degraded/degradation" are not defined in the NERC Glossary of Terms, it is necessary to explore alternative sources for interpretation. A review of the Merriam-Webster Collegiate Dictionary does not provide an adequate definition of the terms in question. As technical experts recognized throughout the electrical industry, the Institute of Electrical and Electronics Engineers, Inc. ("IEEE") defines "degraded" as the inability of an item to perform its required function. Specifically, the IEEE definition of "degraded" is:

> a failure that is gradual, or partial or both; for example, the equipment degrades to a level that, in effect, is a termination of the ability to perform its required function.[1]

Correspondingly, the IEEE definition of "failure (Reliability)" is:

> The termination of the ability of an item to perform its required function.[2]

1 IEEE 100, *The Authoritative Dictionary of IEEE Standards Terms* (7th ed.)

2 Supra no.1

According to the NERC Glossary of Terms, the function of a Special Protection System ("SPS") is "to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability." Since an SPS that has one communication channel out of service can still fully perform this function, Manitoba Hydro submits that under such circumstances the SPS is not "degraded".

Unlike other facilities, Special Protection Systems are required by NERC standards to be designed with redundant communication channels, so that if one communication channel fails the SPS is able to remain in operation. Requirement R1.3 of NERC Standard PRC-012-0 requires a Regional Reliability Organization with Transmission Owners that use SPSs to have a documented review procedure to ensure that SPSs comply with reliability standards and criteria, including: "requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements in TPL-001-0, TPL-002-0 and TPL-003-0". Accordingly, SPSs are designed to continue to perform their function with only one communication channel in service.

Manitoba Hydro believes this is a reasonable interpretation, since in our view the SPS will still operate as required to protect for the next N-1 condition. If the remaining communication channel were to come out of service, power transfers would be reduced to again protect for the next worst N-1 condition.

For the foregoing reasons, Manitoba Hydro respectfully requests an interpretation that clarifies the requirements of NERC Standards TOP-005-0 and IRO-005-0 with respect to Special Protection Systems.

Yours truly,

MANITOBA HYDRO LAW DEPARTMENT
Per:

K. JENNIFER MOROZ
Barrister & Solicitor

KJM/sc

Project 2008-18: Response to Request for an Interpretation of TOP-005-1, Requirement R3; IRO-005-1, Requirement R12; and PRC-012-0, Requirement R1 and R1.3 for Manitoba Hydro

The following interpretation of TOP-005-1 — Operational Reliability Information, Requirement R3; IRO-005-1 — Reliability Coordination — Current Day Operations, Requirement R12; and PRC-012-0 — Special Protection System Review Procedure, Requirements R1 and R1.3 was developed by a subset of the Real-time Operations Standards Drafting Team on December 29, 2008.

Requirement Number and Text of Requirement

TOP-005-1 Requirement R3

Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

The above-referenced Attachment 1 - TOP-005-0 specifies the following data as item 2.6: **New or <u>degraded</u> special protection systems.** ***[Underline added for emphasis.]***

IRO-005-1 Requirement R12

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any <u>degradation</u> or potential failure to operate as expected. ***[Underline added for emphasis.]***

PRC-012-0 Requirements R1 and R1.3

R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:

> **R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.**

Background Information for Interpretation

The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a "responsibility mandate." Requirement R1 establishes who is responsible for the obligation to provide operating data "required" by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a "performance mandate." Requirement R3 defines the obligation to provide data "requested" by other reliability entities that is needed "to perform assessments and to coordinate operations."

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The Attachment to TOP-005-1 is provided as a guideline of what "can be shared." The Attachment is not an obligation of "what must be shared." Enforceable NERC Requirements must be explicitly contained within a given Standard's approved requirements. In this case, the standard only requires data "upon request." If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined "degraded" state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator's obligation to be aware of conditions that may have a "significant" impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term "degraded."

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

Exhibit B

Reliability Standards that includes the Appended Interpretations

A. Introduction

1. **Title:** **Operational Reliability Information**

2. **Number:** TOP-005-1.1a

3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Reliability Coordinators.

   4.4. Purchasing Selling Entities.

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

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.

R1.1. Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.

R2. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."

R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

R4. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

M1. Evidence that the Reliability Coordinator, Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 to R4 is providing the requesting entities with the data required, in specified time intervals and format, but there are problems with consistency of delivery identified in the measuring process that need remedy (e.g., the data is not supplied consistently due to equipment malfunctions, or scaling is incorrect).

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: Each entity responsible for reporting information under Requirements R1 to R4 is not providing the requesting entities with data with the specified content, timeliness, or format. The information missing is included in the requesting entity's list of data.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 6, 2007	Revised D.2.1 and D.2.4 reference "Requirements R1 to R5" "to Requirements R1 to R4."	Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to "1.1"	Errata
1.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1.1a	November 5, 2009	Added Appendix 1 – Interpretation of Requirement R3 approved by BOT on November 5, 2009	Addition

Attachment 1 — TOP-005-1.1

Electric System Reliability Data

This Attachment lists the types of data that Reliability Coordinators, Balancing Authorities, and Transmission Operators are expected to provide, and are expected to share with each other.

1. The following information shall be updated at least every ten minutes:

1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:

1.1.1 Status.

1.1.2 MW or ampere loadings.

1.1.3 MVA capability.

1.1.4 Transformer tap and phase angle settings.

1.1.5 Key voltages.

1.2. Generator data.

1.2.1 Status.

1.2.2 MW and MVAR capability.

1.2.3 MW and MVAR net output.

1.2.4 Status of automatic voltage control facilities.

1.3. Operating reserve.

1.3.1 MW reserve available within ten minutes.

1.4. Balancing Authority demand.

1.4.1 Instantaneous.

1.5. Interchange.

1.5.1 Instantaneous actual interchange with each Balancing Authority.

1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.

1.5.3 Interchange Schedules for the next 24 hours.

1.6. Area Control Error and frequency.

1.6.1 Instantaneous area control error.

1.6.2 Clock hour area control error.

1.6.3 System frequency at one or more locations in the Balancing Authority.

2. Other operating information updated as soon as available.

2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect.

2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.

2.3. Forecast peak demand for current day and next day.

2.4. Forecast changes in equipment status.

2.5. New facilities in place.

2.6. New or degraded special protection systems.

2.7. Emergency operating procedures in effect.

2.8. Severe weather, fire, or earthquake.

2.9. Multi-site sabotage.

Appendix 1

Requirement Number and Text of Requirement
TOP-005-1 Requirement R3 Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability. *The above-referenced Attachment 1 - TOP-005-0 specifies the following data as item 2.6:* New or degraded special protection systems. *[Underline added for emphasis.]* **IRO-005-1 Requirement R12** **R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected. *[Underline added for emphasis.]* **PRC-012-0 Requirements R1 and R1.3** **R1.** Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include: **R1.3.** Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
Background Information for Interpretation
The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a "responsibility mandate." Requirement R1 establishes who is responsible for the obligation to provide operating data "required" by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a "performance mandate." Requirement R3 defines the obligation to provide data "requested" by other reliability entities that is needed "to perform assessments and to coordinate operations." The Attachment to TOP-005-1 is provided as a guideline of what "can be shared." The Attachment is not an obligation of "what must be shared." Enforceable NERC Requirements must be explicitly contained within a given Standard's approved requirements. In this case, the standard only requires data "upon request." If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined "degraded" state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations. IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system. IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange. IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator's obligation to be aware of conditions that may have a "significant" impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator. The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.
Conclusion
The TOP-005-1 standard does not provide, nor does it require, a definition for the term "degraded." The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported. To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

A. Introduction

1. **Title:** **Reliability Coordination — Current Day Operations**

2. **Number:** IRO-005-1a

3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

4. **Applicability**

   4.1. Reliability Coordinators.

   4.2. Balancing Authorities.

   4.3. Transmission Operators.

   4.4. Transmission Service Providers.

   4.5. Generator Operators

   4.6. Load-Serving Entities.

   4.7. Purchasing-Selling Entities

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

B. Requirements

R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:

R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.

R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.4. System real and reactive reserves (actual versus required).

R1.5. Capacity and energy adequacy conditions.

R1.6. Current ACE for all its Balancing Authorities.

R1.7. Current local or Transmission Loading Relief procedures in effect.

R1.8. Planned generation dispatches.

R1.9. Planned transmission or generation outages.

R1.10. Contingency events.

R2. Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.

R3. As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.

R4. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

R5. Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.

R6. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

R7. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.

R8. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

R9. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.

R10. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.

R11. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission

Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R13. Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

R14. Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

R15. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

R16. Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.

R17. When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	August 28, 2006	Added three items that were inadvertently left out to “Applicability” section:	Errata

		4.5 Generator Operators. 4.6 Load-Serving Entities. 4.7 Purchasing-Selling Entities.	
1a	November 5, 2009	Added Appendix 1 – Interpretation of Requirement R12 approved by BOT on November 5, 2009	Addition

Appendix 1

Requirement Number and Text of Requirement
TOP-005-1 Requirement R3 Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability. *The above-referenced Attachment 1 - TOP-005-0 specifies the following data as item 2.6:* New or degraded special protection systems. *[Underline added for emphasis.]* **IRO-005-1 Requirement R12** **R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected. *[Underline added for emphasis.]* **PRC-012-0 Requirements R1 and R1.3** **R1.** Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include: **R1.3.** Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
Background Information for Interpretation
The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a "responsibility mandate." Requirement R1 establishes who is responsible for the obligation to provide operating data "required" by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a "performance mandate." Requirement R3 defines the obligation to provide data "requested" by other reliability entities that is needed "to perform assessments and to coordinate operations." The Attachment to TOP-005-1 is provided as a guideline of what "can be shared." The Attachment is not an obligation of "what must be shared." Enforceable NERC Requirements must be explicitly contained within a given Standard's approved requirements. In this case, the standard only requires data "upon request." If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined "degraded" state). IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability

obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator's obligation to be aware of conditions that may have a "significant" impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term "degraded."

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

Exhibit C

Complete Development Record of the Interpretations

Project 2008-18

Manitoba Hydro Request for Interpretation of the following:

TOP-005-1 — Operational Reliability Information
IRO-005-1 — Reliability Coordination - Current Day Operations

Status:
The interpretation was approved by the NERC Board of Trustees on November 5, 2009 and will be submitted to FERC for approval.

Summary:
Manitoba Hydro requests an interpretation of the meaning of the term "degraded/degradation" as used in NERC Standards TOP-005-1 and IRO-005-1 and specifically, whether a Special Protection System that is operating with only one communication channel in service would be considered "degraded" for the purposes of these standards.

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.

Draft	Action	Dates	Results	Consideration of Comments
Manitoba Hydro Request for Interpretation of the following: TOP-005-1 and IRO-005-1 Interpretation (2) Request for Interpretation (3)	Recirculation Ballot Info>> (8) | Vote>>	4/17/09 - 04/27/09 (closed)	Summary>>(9) Full Record>>(10)	
	Initial Ballot Info>> (4) | Vote>>	3/19/09 - 03/30/09 (closed)	Summary>> (5) Full Record>> (6)	Consideration of Comments>> (7)
	Pre-ballot Review (1) Info>> | Join>>	02/18/09 - 03/19/09 (closed)		

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Standards Announcement

Ballot Pool and Pre-ballot Window
February 18–March 19, 2009

Now available at: https://standards.nerc.net/BallotPool.aspx

Interpretation of TOP-005-1 and IRO-005-1 for Manitoba Hydro (Project 2008-18)

An interpretation of TOP-005-1 — Operational Reliability Information and IRO-005-1 — Reliability Coordination — Current Day Operations for Manitoba Hydro is posted for a 30-day pre-ballot review. Registered Ballot Body members may join the ballot pool to be eligible to vote on this interpretation **until 8 a.m. EDT on March 19, 2009**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using ballot pool list servers.) The list server for this ballot pool is: bp-2008-18_RFI_Manitoba_in.

Project Background

Manitoba Hydro requested an interpretation of the meaning of the term "degraded/degradation" as used in NERC standards TOP-005-1 and IRO-005-1 and specifically, whether a Special Protection System that is operating with only one communication channel in service would be considered "degraded" for the purposes of these standards. The request and interpretation are posted on the project page: http://www.nerc.com/filez/standards/Project2008-18_Interpretation_TOP-005-1_IRO-005-1_ManitobaHydro.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard	
Date submitted: **November 25, 2008**	
Contact information for person requesting the interpretation:	
Name:	**K. Jennifer Moroz**
Organization:	**Manitoba Hydro**
Telephone:	**(204) 474-4539**
E-mail:	**kjmoroz@hydro.mb.ca**
Identify the standard that needs clarification:	
TOP-005-1 — Operational Reliability Information **IRO-005-1 — Reliability Coordination - Current Day Operations** **PRC-012-0 — Special Protection System Review Procedure**	
Identify specifically what needs clarification (If a category is not applicable, please leave it blank)**:**	

TOP-005-1 Requirement R3.

R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

> ***The above-referenced Attachment 1 - TOP-005-0 specifies the following data as item 2.6:***
>
> **2.6. New or <u>degraded</u> special protection systems. *[Underline added for emphasis.]***

IRO-005-1 Requirement R12.

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of

the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any <u>degradation</u> or potential failure to operate as expected. ***[Underline added for emphasis.]*** **PRC-012-0 Requirement R1 and R1.3:** **R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:** **R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.** **Clarification needed** **See attached letter.**
Identify the material impact associated with this interpretation:
Noncompliance could result in penalties and sanctions.

P.O. Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 3rd floor – 820 Taylor Avenue
Telephone / No de téléphone : (204) 474-4539 • Fax / No de télécopieur : (204) 474-4947
kjmoroz@hydro.mb.ca

November 25, 2008

The North American Electric Reliability Corporation
Princeton Forrestal Village
115 Village Boulevard
PRINCETON, New Jersey
U.S.A. 08540-5731

ATTENTION: **Ms. Maureen E. Long , Standards Process Manager**

Dear Ms. Long:

RE: REQUEST FOR INTERPRETATION OF NERC STANDARDS TOP-005-1; IRO-005-1

Manitoba Hydro respectfully requests an interpretation of Reliability Standards TOP-005-1 and IRO-005-1 pursuant to Appendix 3A of the North American Electric Reliability Corporation's ("NERC") Rules of Procedure. As a Balancing Authority and an operator of transmission facilities that is bound by Manitoba law to adhere to NERC reliability standards, except as modified or disallowed by order of the government of Manitoba, Manitoba Hydro is directly and materially affected by the above-referenced standards. Accordingly, Manitoba Hydro is entitled to request NERC's interpretation of these standards, pursuant to Appendix 3A of the NERC Rules of Procedure.

Request

Manitoba Hydro requests an interpretation of the meaning of the term "degraded/degradation" as used in NERC Standards TOP-005-1 and IRO-005-1 and specifically, whether a Special Protection System that is operating with only one communication channel in service would be considered "degraded" for the purposes of these standards.

Standards To Be Interpreted

NERC Standard TOP-005-1 entitled "Operational Reliability Information" governs the operating data that is required by various reliability entities to monitor system conditions within their area. Requirement R3 of TOP-005-1 obligates Balancing Authorities and Transmission Operators to provide the types of data as listed in Attachment 1 - TOP-005-0 ("Electric System Reliability Data"), to other Balancing Authorities and Transmission Operators unless otherwise agreed. The above-referenced Attachment 1 - TOP-005-0 specifies the following data as item 2.6:

> "2.6 New or <u>degraded</u> special protection systems."

Similarly, NERC Standard IRO-005-1 entitled "Reliability Coordination - Current Day Operations", which governs the monitoring responsibilities of Reliability Coordinators, includes requirements for the exchange of information between Transmission Operators and their respective Reliability Coordinators concerning special protection systems. Requirement R12 of IRO-005-1 provides the following:

> "The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any <u>degradation</u> or potential failure to operate as expected."

<u>Basis for Clarification</u>

Manitoba Hydro respectfully requests that NERC clarify that a Special Protection System is not considered "degraded" for the purpose of the above-referenced NERC Standards if it is operating with one communication channel out of service. Manitoba Hydro considers this to be a reasonable interpretation for the following reasons.

Since the terms "degraded/degradation" are not defined in the NERC Glossary of Terms, it is necessary to explore alternative sources for interpretation. A review of the Merriam-Webster Collegiate Dictionary does not provide an adequate definition of the terms in question. As technical experts recognized throughout the electrical industry, the Institute of Electrical and Electronics Engineers, Inc. ("IEEE") defines "degraded" as the inability of an item to perform its required function. Specifically, the IEEE definition of "degraded" is:

> a <u>failure</u> that is gradual, or partial or both; for example, the equipment degrades to a level that, in effect, is a termination of the ability to perform its required function.[1]

Correspondingly, the IEEE definition of "failure (Reliability)" is:

> The termination of the ability of an item to perform its required function.[2]

1 IEEE 100, *The Authoritative Dictionary of IEEE Standards Terms* (7th ed.)
2 Supra no.1

According to the NERC Glossary of Terms, the function of a Special Protection System ("SPS") is "to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability." Since an SPS that has one communication channel out of service can still fully perform this function, Manitoba Hydro submits that under such circumstances the SPS is not "degraded".

Unlike other facilities, Special Protection Systems are required by NERC standards to be designed with redundant communication channels, so that if one communication channel fails the SPS is able to remain in operation. Requirement R1.3 of NERC Standard PRC-012-0 requires a Regional Reliability Organization with Transmission Owners that use SPSs to have a documented review procedure to ensure that SPSs comply with reliability standards and criteria, including: "requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements in TPL-001-0, TPL-002-0 and TPL-003-0". Accordingly, SPSs are designed to continue to perform their function with only one communication channel in service.

Manitoba Hydro believes this is a reasonable interpretation, since in our view the SPS will still operate as required to protect for the next N-1 condition. If the remaining communication channel were to come out of service, power transfers would be reduced to again protect for the next worst N-1 condition.

For the foregoing reasons, Manitoba Hydro respectfully requests an interpretation that clarifies the requirements of NERC Standards TOP-005-0 and IRO-005-0 with respect to Special Protection Systems.

Yours truly,

MANITOBA HYDRO LAW DEPARTMENT
Per:

K. JENNIFER MOROZ
Barrister & Solicitor

KJM/sc

Project 2008-18: Response to Request for an Interpretation of TOP-005-1, Requirement R3; IRO-005-1, Requirement R12; and PRC-012-0, Requirement R1 and R1.3 for Manitoba Hydro

The following interpretation of TOP-005-1 — Operational Reliability Information, Requirement R3; IRO-005-1 — Reliability Coordination — Current Day Operations, Requirement R12; and PRC-012-0 — Special Protection System Review Procedure, Requirements R1 and R1.3 was developed by a subset of the Real-time Operations Standards Drafting Team on December 29, 2008.

Requirement Number and Text of Requirement

TOP-005-1 Requirement R3

Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

The above-referenced Attachment 1 - TOP-005-0 specifies the following data as item 2.6: **New or <u>degraded</u> special protection systems.** ***[Underline added for emphasis.]***

IRO-005-1 Requirement R12

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any <u>degradation</u> or potential failure to operate as expected. ***[Underline added for emphasis.]***

PRC-012-0 Requirements R1 and R1.3

R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:

> **R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.**

Background Information for Interpretation

The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a "responsibility mandate." Requirement R1 establishes who is responsible for the obligation to provide operating data "required" by a Reliability

Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a "performance mandate." Requirement R3 defines the obligation to provide data "requested" by other reliability entities that is needed "to perform assessments and to coordinate operations."

The Attachment to TOP-005-1 is provided as a guideline of what "can be shared." The Attachment is not an obligation of "what must be shared." Enforceable NERC Requirements must be explicitly contained within a given Standard's approved requirements. In this case, the standard only requires data "upon request." If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined "degraded" state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator's obligation to be aware of conditions that may have a "significant" impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term "degraded."

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition

can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

When completed, email this form to:
maureen.long@nerc.net
For questions about this form or for assistance in completing the form, call Maureen Long at 813-468-5998.

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard

Date submitted: **November 25, 2008**

Contact information for person requesting the interpretation:

Name: **K. Jennifer Moroz**

Organization: **Manitoba Hydro**

Telephone: **(204) 474-4539**

E-mail: **kjmoroz@hydro.mb.ca**

Identify the standard that needs clarification:

TOP-005-1 — Operational Reliability Information

IRO-005-1 — Reliability Coordination - Current Day Operations

PRC-012-0 — Special Protection System Review Procedure

Identify specifically what needs clarification (If a category is not applicable, please leave it blank):

TOP-005-1 Requirement R3.

R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

> ***The above-referenced Attachment 1 - TOP-005-0 specifies the following data as item 2.6:***
>
> **2.6. New or degraded special protection systems. *[Underline added for emphasis.]***

IRO-005-1 Requirement R12.

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The

Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected. ***[Underline added for emphasis.]*** **PRC-012-0 Requirement R1 and R1.3:** **R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:** **R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.** **Clarification needed** **See attached letter.**
Identify the material impact associated with this interpretation:
Noncompliance could result in penalties and sanctions.

Manitoba Hydro

P.O. Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 3rd floor – 820 Taylor Avenue
Telephone / Nº de téléphone : (204) 474-4539 • Fax / Nº de télécopieur : (204) 474-4947
kjmoroz@hydro.mb.ca

November 25, 2008

The North American Electric Reliability Corporation
Princeton Forrestal Village
115 Village Boulevard
PRINCETON, New Jersey
U.S.A. 08540-5731

ATTENTION: **Ms. Maureen E. Long , Standards Process Manager**

Dear Ms. Long:

RE: REQUEST FOR INTERPRETATION OF NERC STANDARDS TOP-005-1; IRO-005-1

Manitoba Hydro respectfully requests an interpretation of Reliability Standards TOP-005-1 and IRO-005-1 pursuant to Appendix 3A of the North American Electric Reliability Corporation's ("NERC") Rules of Procedure. As a Balancing Authority and an operator of transmission facilities that is bound by Manitoba law to adhere to NERC reliability standards, except as modified or disallowed by order of the government of Manitoba, Manitoba Hydro is directly and materially affected by the above-referenced standards. Accordingly, Manitoba Hydro is entitled to request NERC's interpretation of these standards, pursuant to Appendix 3A of the NERC Rules of Procedure.

Request

Manitoba Hydro requests an interpretation of the meaning of the term "degraded/degradation" as used in NERC Standards TOP-005-1 and IRO-005-1 and specifically, whether a Special Protection System that is operating with only one communication channel in service would be considered "degraded" for the purposes of these standards.

Standards To Be Interpreted

NERC Standard TOP-005-1 entitled "Operational Reliability Information" governs the operating data that is required by various reliability entities to monitor system conditions within their area. Requirement R3 of TOP-005-1 obligates Balancing Authorities and Transmission Operators to provide the types of data as listed in Attachment 1 - TOP-005-0 ("Electric System Reliability

Data"), to other Balancing Authorities and Transmission Operators unless otherwise agreed. The above-referenced Attachment 1 - TOP-005-0 specifies the following data as item 2.6:

> "2.6 New or degraded special protection systems."

Similarly, NERC Standard IRO-005-1 entitled "Reliability Coordination - Current Day Operations", which governs the monitoring responsibilities of Reliability Coordinators, includes requirements for the exchange of information between Transmission Operators and their respective Reliability Coordinators concerning special protection systems. Requirement R12 of IRO-005-1 provides the following:

> "The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected."

Basis for Clarification

Manitoba Hydro respectfully requests that NERC clarify that a Special Protection System is not considered "degraded" for the purpose of the above-referenced NERC Standards if it is operating with one communication channel out of service. Manitoba Hydro considers this to be a reasonable interpretation for the following reasons.

Since the terms "degraded/degradation" are not defined in the NERC Glossary of Terms, it is necessary to explore alternative sources for interpretation. A review of the Merriam-Webster Collegiate Dictionary does not provide an adequate definition of the terms in question. As technical experts recognized throughout the electrical industry, the Institute of Electrical and Electronics Engineers, Inc. ("IEEE") defines "degraded" as the inability of an item to perform its required function. Specifically, the IEEE definition of "degraded" is:

> a failure that is gradual, or partial or both; for example, the equipment degrades to a level that, in effect, is a termination of the ability to perform its required function.[1]

Correspondingly, the IEEE definition of "failure (Reliability)" is:

> The termination of the ability of an item to perform its required function.[2]

According to the NERC Glossary of Terms, the function of a Special Protection System ("SPS") is "to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability." Since an

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1 IEEE 100, *The Authoritative Dictionary of IEEE Standards Terms* (7th ed.)
2 Supra no.1

SPS that has one communication channel out of service can still fully perform this function, Manitoba Hydro submits that under such circumstances the SPS is not “degraded”.

Unlike other facilities, Special Protection Systems are required by NERC standards to be designed with redundant communication channels, so that if one communication channel fails the SPS is able to remain in operation. Requirement R1.3 of NERC Standard PRC-012-0 requires a Regional Reliability Organization with Transmission Owners that use SPSs to have a documented review procedure to ensure that SPSs comply with reliability standards and criteria, including: “requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements in TPL-001-0, TPL-002-0 and TPL-003-0”. Accordingly, SPSs are designed to continue to perform their function with only one communication channel in service.

Manitoba Hydro believes this is a reasonable interpretation, since in our view the SPS will still operate as required to protect for the next N-1 condition. If the remaining communication channel were to come out of service, power transfers would be reduced to again protect for the next worst N-1 condition.

For the foregoing reasons, Manitoba Hydro respectfully requests an interpretation that clarifies the requirements of NERC Standards TOP-005-0 and IRO-005-0 with respect to Special Protection Systems.

Yours truly,

MANITOBA HYDRO LAW DEPARTMENT
Per:

K. JENNIFER MOROZ
Barrister & Solicitor

KJM/sc

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Window Open

March 19–30, 2009

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Interpretation of TOP-005-1 and IRO-005-1 for Manitoba Hydro (Project 2008-18)

An initial ballot window for an interpretation of TOP-005-1 — Operational Reliability Information and IRO-005-1 — Reliability Coordination — Current Day Operations for Manitoba Hydro is now open **until 8 p.m. EDT on March 30, 2009**.

Project Background

Manitoba Hydro requested an interpretation of the meaning of the term "degraded/degradation" as used in NERC standards TOP-005-1 and IRO-005-1 and specifically, whether a Special Protection System that is operating with only one communication channel in service would be considered "degraded" for the purposes of these standards. The request and interpretation are posted on the project page: http://www.nerc.com/filez/standards/Project2008-18_Interpretation_TOP-005-1_IRO-005-1_ManitobaHydro.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Standards Announcement

Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Interpretation of TOP-005-1 and IRO-005-1 for Manitoba Hydro (Project 2008-18)
Since at least one negative ballot was submitted with a comment, a recirculation ballot will be held. The recirculation ballot will be held after the drafting team responds to voter comments submitted during this ballot.

The initial ballot for an interpretation of TOP-005-1 — Operational Reliability Information and IRO-005-1 — Reliability Coordination — Current Day Operations for Manitoba Hydro ended March 30, 2009. The ballot results are shown below. The Ballot Results Web page provides a link to the detailed results.

Quorum: 89.78%
Approval: 92.62%

Project page: http://www.nerc.com/filez/standards/Project2008-18_Interpretation_TOP-005-1_IRO-005-1_ManitobaHydro.html

Ballot Criteria
Approval requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses.

Standards Development Process
The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Ballot Results	
Ballot Name:	Project 2008-18 Interpretation-Manitoba Hydro_in
Ballot Period:	3/19/2009 - 3/30/2009
Ballot Type:	Initial
Total # Votes:	202
Total Ballot Pool:	225
Quorum:	89.78 % The Quorum has been reached
Weighted Segment Vote:	92.62 %
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.	63	1	50	0.943	3	0.057	2	8
2 - Segment 2.	9	0.8	8	0.8	0	0	0	1
3 - Segment 3.	57	1	46	0.939	3	0.061	4	4
4 - Segment 4.	12	1	10	1	0	0	0	2
5 - Segment 5.	45	1	33	0.892	4	0.108	4	4
6 - Segment 6.	25	1	20	0.909	2	0.091	0	3
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	2	0.1	1	0.1	0	0	1	0
9 - Segment 9.	3	0.2	2	0.2	0	0	0	1
10 - Segment 10.	9	0.9	7	0.7	2	0.2	0	0
Totals	225	7	177	6.483	14	0.517	11	23

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Jason Shaver	Affirmative	View
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney		
1	Baltimore Gas & Electric Company	John J. Moraski	Affirmative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	

1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Alan L Cooke	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dominion Virginia Power	William L. Thompson		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S. LLC	Larry Monday	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	Farmington Electric Utility System	Alan Glazner		
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
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	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Kissimmee Utility Authority	Joe B Watson	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	National Grid	Manuel Couto	Affirmative	
1	New Brunswick Power Transmission Corporation	Brian Scott		
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	View
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Abstain	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Alan Derichsweiler	Negative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	View
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	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	View
3	American Electric Power	Raj Rana	Negative	View
3	Arizona Public Service Co.	Thomas R. Glock	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	Affirmative	
3	Cleco Utility Group	Bryan Y Harper		
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost		
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	View
3	Florida Power & Light Co.	W. R. Schoneck	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Georgia System Operations Corporation	Edward W Pourciau	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Abstain	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Jamie Hall	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Michael Lupo	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Affirmative	View
3	PECO Energy an Exelon Co.	John J. McCawley	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	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	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Turlock Irrigation District	Casey Hashimoto	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Sacramento Municipal Utility District	Dilip Mahendra		
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	

4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	Amerenue	Sam Dwyer	Negative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Affirmative	View
5	City of Tallahassee	Alan Gale	Affirmative	
5	Cleco Power LLC	Grant Bryant		
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Dynegy	Greg Mason	Affirmative	
5	Electric Power Supply Association	Jack R. Cashin	Abstain	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	FPL Energy	Benjamin Church		
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Northern States Power Co.	Liam Noailles	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	PacifiCorp Energy	David Godfrey	Affirmative	View
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Thomas Piascik	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Negative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Abstain	
5	Southeastern Power Administration	Douglas Spencer	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	Frank L Busot	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Negative	
5	Tennessee Valley Authority	Frank D Cuzzort		
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	View
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
6	AEP Marketing	Edward P. Cox		
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Exelon Power Team	Pulin Shah		
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Kansas City Power & Light Co.	Thomas Saitta	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	PacifiCorp	Gregory D Maxfield	Affirmative	View
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Reliant Energy Services	Trent Carlson	Negative	View
6	Salt River Project	Mike Hummel		

6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Southern California Edison Co.	Marcus V Lotto	Affirmative	
6	Tampa Electric Co.	Heidi Giustiniani	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy Zito	Affirmative	View
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	View
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

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Consideration of Comments on Initial Ballot for Project 2008-18: Manitoba Hydro Request for Interpretation (TOP-005-1 — Operational Reliability Information, IRO-005-1 — Reliability Coordination — Current Day Operations)

Summary Consideration:
Several stakeholders offered alternative views of the term degraded and suggested a formal definition be drafted. An interpretation of a standard does not permit the creation of requirements or definitions. Absent a specific definition of the term degraded, the SDT provided its subjective evaluation of the intent of the word. As stated in the interpretation, the Standard Drafting Team (SDT) has no objection to a formal definition being proposed and adopted. The SDT invites the requestor or those who offered comments and suggestions to submit a Standard Authorization Request (SAR) to modify the standard with a proposed definition. As part of the standards development process, any person that is directly and materially affected by an existing standard or the need for a new standard may submit a new standard or revision to a standard.

Given that the intent of the interpretation is not materially changed by the comments received, the SDT does not believe another posting is justified.

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	The interpretation includes an implied definition of the term degradation; that is, degradation is a condition that will result in a failure of an SPS to operate as designed. We disagree with definition of degradation. Without a formal definition of degraded, we think that logic would imply you have three ways to describe the state of something: 1) all is well, 2) something is amiss but its working, 3) and the thing is not functioning. From our perspective, the word degrade fits into the category of 2) and failure into the category of 3). This interpretation puts degraded into category of 3). Further, the IRO-005-2, R12 requires the TOP to inform RC the status of the SPS including any degradation or potential failure to operate as expected. Two conditions are included in the R12 requirement; the first is degradation and the second one is a potential failure to operate as expected. The SDT's interpretation states that the first condition implies the second one and thereby degradation is a condition that will result in a failure of an SPS to operate as designed. If this was the intent, why would the wordings "any degradation" be specifically included in this requirement? We believe that the intent here is to inform the RC when the status of SPS is less than robust, that is when the redundancy (in this case one of the communication channels) is not available or not in-service. We do not agree with this part of the interpretation for R12 either.

Voter	Entity	Segment	Vote	Comment
Mark Peters	Ameren Services	3	Negative	The interpretation includes an implied definition of the term degradation; that is, degradation is a condition that will result in a failure of an SPS to operate as designed. We disagree with definition of degradation. Without a formal definition of degraded, we think that logic would imply you have three ways to describe the state of something: 1) all is well, 2) something is amiss but its working, 3) and the thing is not functioning. From our perspective, the word degrade fits into the category of 2) and failure into the category of 3). This interpretation puts degraded into category of 3). Further, the IRO-005-2, R12 requires the TOP to inform RC the status of the SPS including any degradation or potential failure to operate as expected. Two conditions are included in the R12 requirement; the first is degradation and the second one is a potential failure to operate as expected. The SDT's interpretation states that the first condition implies the second one and thereby degradation is a condition that will result in a failure of an SPS to operate as designed. If this was the intent, why would the wordings "any degradation" be specifically included in this requirement? We believe that the intent here is to inform the RC when the status of SPS is less than robust, that is when the redundancy (in this case one of the communication channels) is not available or not in-service. We do not agree with this part of the interpretation for R12 either
Response: An interpretation of a standard does not permit the creation of requirements or definitions. Absent a specific definition of the term degraded, the SDT provided its subjective evaluation of the intent of the word. As stated in the interpretation, the SDT has no objection to a formal definition being proposed and adopted. The SDT invites the commenter to submit a SAR to modify the standard with a proposed definition. The phrase "any degradation or potential failure to operate as expected" was interpreted to mean "any actual or any forecasted condition that would result in the SPS not operating as expected." It was viewed as separating a fact from an expectation. The commenter is invited to draft a SAR that will formally define "less than robust" and which "redundancy devices" must be monitored and reported upon.				
Paul B. Johnson	American Electric Power	1	Negative	AEP believes that the term "degraded" should be clarified such that an entity can be evaluated on a known measurable basis and not based on implication. AEP agrees with the SDT's interpretation that "degraded" is a condition that will result in the failure of an SPS to operate as designed, but does not agree that a definition is unnecessary in the standards. SPSs' are designed so that no one component failure will prevent the SPS to operate as designed. Although there may be other ways to ensure this functionality, redundant systems are most likely used. In such circumstances, with one system component failure, the system would still be able to function and there would be no

Voter	Entity	Segment	Vote	Comment
				requirement for the SPS unit to be reported. However, when an SPS alone is not operating as designed (a degraded SPS), the SPS is not functional (or broken) and should be removed from the BES. Consequently, the use of this term without definition does not create the specificity of reporting that the standard is intended to provide.
Raj Rana	American Electric Power	3	Negative	AEP believes that the term "degraded" should be clarified such that an entity can be evaluated on a known measurable basis and not based on implication. AEP agrees with the SDT's interpretation that "degraded" is a condition that will result in the failure of an SPS to operate as designed, but does not agree that a definition is unnecessary in the standards. SPSs' are designed so that no one component failure will prevent the SPS to operate as designed. Although there may be other ways to ensure this functionality, redundant systems are most likely used. In such circumstances, with one system component failure, the system would still be able to function and there would be no requirement for the SPS unit to be reported. However, when an SPS alone is not operating as designed (a degraded SPS), the SPS is not functional (or broken) and should be removed from the BES. Consequently, the use of this term without definition does not create the specificity of reporting that the standard is intended to provide.
Brock Ondayko	AEP Service Corp.	5	Negative	AEP believes that the term "degraded" should be clarified such that an entity can be evaluated on a known measurable basis and not based on implication. AEP agrees with the SDT's interpretation that "degraded" is a condition that will result in the failure of an SPS to operate as designed, but does not agree that a definition is unnecessary in the standards. SPSs' are designed so that no one component failure will prevent the SPS to operate as designed. Although there may be other ways to ensure this functionality, redundant systems are most likely used. In such circumstances, with one system component failure, the system would still be able to function and there would be no requirement for the SPS unit to be reported. However, when an SPS alone is not operating as designed (a degraded SPS), the SPS is not functional (or broken) and should be removed from the BES. Consequently, the use of this term without definition does not create the specificity of reporting that the standard is intended to provide.

Response: An interpretation of a standard does not permit the creation of requirements or definitions. Absent a specific definition of the term degraded, the SDT provided its subjective evaluation of the intent of the word.

As stated in the interpretation, the SDT has no objection to a formal definition being proposed and adopted. The SDT invites the commenter to submit a SAR to modify the standard with a proposed definition.

Voter	Entity	Segment	Vote	Comment
The SDT phrase "a definition is unnecessary in the standards" was meant to indicate that this standard as written could exist without a formal definition, not that formal definitions are not needed in this or in any other standard. As noted above, if the commenter believes that the standard itself is incorrect or needs an explicit definition for degraded, the commenter is urged to submit a SAR with the appropriate additions, modifications, or deletions.				
Jason Shaver	American Transmission Company, LLC	1	Affirmative	In general ATC agrees with the interpretation, but we believe that the following change should be considered: Replace the phrase "as designed" with "as expected" IRO-005 Requirement 12 uses the phrase "as expected" not "as designed". The term "designed" is used in PRC-012 Requirement 1.3. Since the interpretation is for IRO-005 Requirement 12 we believe that the interpretation would be clearer if the identical phrase is used. Modified Interpretation would read: "... If the loss of the communication channel will result in the failure of an SPS to operate as expected, then the Transmission Operator would be mandated to report the information. ..."
Response: Thank you for the support and the proposed suggestion. Given that the intent of the interpretation is not materially changed by the proposed change, the SDT does not believe another posting is justified.				
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	"FirstEnergy Corp. agrees with the interpretation and is voting AFFIRMATIVE. Per the current requirements of these standards as written today, the interpretation is correct. Standard IRO-005 addresses real time operations and not design requirements. The standard is intended to make sure the RC is aware of an SPS that will not operate properly. Assuming that a single communication channel failure does not render the SPS inoperable, then the loss of that channel has no impact as far as the RC is concerned. From a good utility practice view, if it becomes known to the TOP that the SPS back-up communication channel will be out for an extended period of time, then we believe this merits reporting to the RC so that the RC is aware of the situation. But since one cannot make these assumptions based on the requirements as presently written, the interpretation is correct. It should be expected that upon approval of this industry interpretation that the wording for "degraded" be revised to reflect "inoperable" if that is the conclusion of the interpretation. Additionally, the standards development process should further consider during real-time operations whether or not the RC needs to be made aware of loss of redundancy within an SPS design. FE proposes that the existing NERC standards development project 2007-18 should consider the results of this interpretation within their work scope and complete further refinements to the IRO-005 standard."

Voter	Entity	Segment	Vote	Comment
Joanne Kathleen Borrell	FirstEnergy Solutions	3	Affirmative	"FirstEnergy Corp. agrees with the interpretation and is voting AFFIRMATIVE. Per the current requirements of these standards as written today, the interpretation is correct. Standard IRO-005 addresses real time operations and not design requirements. The standard is intended to make sure the RC is aware of an SPS that will not operate properly. Assuming that a single communication channel failure does not render the SPS inoperable, then the loss of that channel has no impact as far as the RC is concerned. From a good utility practice view, if it becomes known to the TOP that the SPS back-up communication channel will be out for an extended period of time, then we believe this merits reporting to the RC so that the RC is aware of the situation. But since one cannot make these assumptions based on the requirements as presently written, the interpretation is correct. It should be expected that upon approval of this industry interpretation that the wording for "degraded" be revised to reflect "inoperable" if that is the conclusion of the interpretation. Additionally, the standards development process should further consider during real-time operations whether or not the RC needs to be made aware of loss of redundancy within an SPS design. FE proposes that the existing NERC standards development project 2007-18 should consider the results of this interpretation within their work scope and complete further refinements to the IRO-005 standard."
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	FirstEnergy Corp. agrees with the interpretation and is voting AFFIRMATIVE. Per the current requirements of these standards as written today, the interpretation is correct. Standard IRO-005 addresses real time operations and not design requirements. The standard is intended to make sure the RC is aware of an SPS that will not operate properly. Assuming that a single communication channel failure does not render the SPS inoperable, then the loss of that channel has no impact as far as the RC is concerned. From a good utility practice view, if it becomes known to the TOP that the SPS back-up communication channel will be out for an extended period of time, then we believe this merits reporting to the RC so that the RC is aware of the situation. But since one cannot make these assumptions based on the requirements as presently written, the interpretation is correct. It should be expected that upon approval of this industry interpretation that the wording for "degraded" be revised to reflect "inoperable" if that is the conclusion of the interpretation. Additionally, the standards development process should further consider during real-time operations whether or not the RC needs to be made aware of loss of redundancy within an SPS design. FE proposes that the existing NERC standards development project 2007-18 should consider the results of this

Voter	Entity	Segment	Vote	Comment
				interpretation within their work scope and complete further refinements to the IRO-005 standard.
Kenneth Dresner	FirstEnergy Solutions	5	Affirmative	Per the current requirements of these standards as written today, the interpretation is correct. Standard IRO-005 addresses real time operations and not design requirements. The standard is intended to make sure the RC is aware of an SPS that will not operate properly. Assuming that a single communication channel failure does not render the SPS inoperable, then the loss of that channel has no impact as far as the RC is concerned. From a good utility practice view, if it becomes known to the TOP that the SPS back-up communication channel will be out for an extended period of time, then we believe this merits reporting to the RC so that the RC is aware of the situation. But since one cannot make these assumptions based on the requirements as presently written, the interpretation is correct. It should be expected that upon approval of this industry interpretation that the wording for "degraded" be revised to reflect "inoperable" if that is the conclusion of the interpretation. Additionally, the standards development process should further consider during real-time operations whether or not the RC needs to be made aware of loss of redundancy within an SPS design. FE proposes that the existing NERC standards development project 2007-18 should consider the results of this interpretation within their work scope and complete further refinements to the IRO-005 standard."
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	FirstEnergy Corp. agrees with the interpretation and is voting AFFIRMATIVE. Per the current requirements of these standards as written today, the interpretation is correct. Standard IRO-005 addresses real time operations and not design requirements. The standard is intended to make sure the RC is aware of an SPS that will not operate properly. Assuming that a single communication channel failure does not render the SPS inoperable, then the loss of that channel has no impact as far as the RC is concerned. From a good utility practice view, if it becomes known to the TOP that the SPS back-up communication channel will be out for an extended period of time, then we believe this merits reporting to the RC so that the RC is aware of the situation. But since one cannot make these assumptions based on the requirements as presently written, the interpretation is correct. It should be expected that upon approval of this industry interpretation that the wording for "degraded" be revised to reflect "inoperable" if that is the conclusion of the interpretation. Additionally, the standards development process should further consider during real-time operations whether or not the RC needs to be made aware of loss of redundancy within an SPS design. FE proposes that the existing

Voter	Entity	Segment	Vote	Comment
				NERC standards development project 2007-18 should consider the results of this interpretation within their work scope and complete further refinements to the IRO-005 standard.
Response: Thank you for your support. Your comment regarding Project 2007-18 (Reliability-based Control) will be shared with that project's SDT.				
Brad Chase	Orlando Utilities Commission	1	Abstain	OUC does not have any SPS in place and therefore let those that do have them influence the vote.
Response: Thank you for your comment.				
Terry Bilke	Midwest ISO, Inc.	2	Affirmative	We have a major concern in that there is no way to tell who drafted the interpretation. This is true for the other interpretation out for pre-ballot review. This lack of transparency is sure to give people the impression that the interpretation process could be manipulated. Finally, the lack of a comment period precludes the assembly of information that could improve the quality of the interpretation. Speed should not take priority over quality.
Response: The comment concerns process as opposed to content. Changes to the process are not within the scope of this team. Process questions and comments may be directed to the NERC standards process manager.				
Russell A Noble	Cowlitz County PUD	3	Negative	The interpretation is confusing. It implies that all conditions which may result in an SPS to mis-operate must be reported, even if such a report would be quite obvious: i.e. loss of both communication lines will result in the failure of the SPS to operate as designed. Also implied is that an SPS must have redundancy, although no such requirement is made in standard IRO-005-1, or any other standard for that matter. If the SPS is designed with one communication line, a report of a condition must be filed. The interpretation fails to clarify the intent of the use of the word "degradation" and whether failure of redundancy is a degraded condition. If "degradation" can be loss of redundancy, then there should be a corresponding requirement in a standard that an SPS must be designed with redundancy.
Response: The interpretation is predicated on "changes in operating conditions," as opposed to a list of "possible conditions." There are no implied requirements in the interpretation. An interpretation of a standard does not permit the creation of requirements or definitions.				

Voter	Entity	Segment	Vote	Comment
Absent a specific definition of the term degraded, the SDT provided its subjective evaluation of the intent of the word. As stated in the interpretation, the SDT has no objection to a formal definition being proposed and adopted. The SDT invites the commenter to submit a SAR to modify the standard with a proposed definition.				
John Apperson	PacifiCorp	3	Affirmative	While performing NERC required maintenance, making programming changes, upgrades, or due to a component failure of an SPS a transmission owner may have one of the two redundant SPS's out of service. If the remaining SPS fails, does the transmission owner have the 30 minute window according to TOP standards to bring the system into a non-SPS required state (within planned AROL and SOL limits) without a TOP/TPL requirement violation? If the answer is yes to the above and a system condition occurs within the 30 minute window, but prior to reaching a non-SPS required state and it results in a system disturbance, is this a violation of the TPL requirements? If a system event occurs requiring the only remaining SPS to operate and it fails to function as designed, resulting in a disturbance, is this considered a single point of failure according to the TPL requirements?
David Godfrey	PacifiCorp Energy	5	Affirmative	While performing NERC required maintenance, making programming changes, upgrades, or due to a component failure of an SPS a transmission owner may have one of the two redundant SPS's out of service. If the remaining SPS fails, does the transmission owner have the 30 minute window according to TOP standards to bring the system into a non-SPS required state (within planned AROL and SOL limits) without a TOP/TPL requirement violation? If the answer is yes to the above and a system condition occurs within the 30 minute window, but prior to reaching a non-SPS required state and it results in a system disturbance, is this a violation of the TPL requirements? If a system event occurs requiring the only remaining SPS to operate and it fails to function as designed, resulting in a disturbance, is this considered a single point of failure according to the TPL requirements?

Voter	Entity	Segment	Vote	Comment
Gregory D Maxfield	PacifiCorp	6	Affirmative	While performing NERC required maintenance, making programming changes, upgrades, or due to a component failure of an SPS, a transmission owner may have one of the two redundant SPS's out of service. Q1. If the remaining SPS fails, does the transmission owner have the 30 minute window according to TOP standards to bring the system into a non-SPS required state (within planned AROL and SOL limits) without a TOP/TPL requirement violation? Q2. If the answer is yes to the above and a system condition occurs within the 30 minute window, but prior to reaching a non-SPS required state and it results in a system disturbance, is this a violation of the TPL requirements? Q3. If a system event occurs requiring the only remaining SPS to operate and it fails to function as designed, resulting in a disturbance, is this considered a single point of failure according to the TPL requirements?
Response: This interpretation specifically addresses IRO-005-2 and is not intended to address scenarios involving other standards. Comments and questions regarding TPL requirements may be addressed to the SDT working on Project 2006-02 (Assess Transmission Future Needs and Develop Transmission Plans). The interpretation states that the asset owner is responsible for determining when the SPS is in danger of not being able to operate. The question the Transmission Operator must ask is, "Is the current state of activities rendering the SPS inoperable?" If yes, the situation should be communicated to the Reliability Coordinator. If no, there is no "mandate" to tell the Reliability Coordinator, but neither is there a prohibition from reporting to the Reliability Coordinator what is happening. If there were two redundant SPSs, and one is inoperable due to maintenance or any other of the stated conditions, the Transmission Operator must decide if the operating system will "work normally" with only one SPS. If yes, then there is no "mandate" to tell the Reliability Coordinator, but again there is no prohibition from reporting to the Reliability Coordinator what is happening. If no, then the situation should be communicated to the Reliability Coordinator.				
John Yale	Chelan County Public Utility District #1	5	Affirmative	It sems a good definition for "degraded" is essential is applying this standard and should be developed.
Response: As stated in the interpretation, the SDT has no objection to a formal definition being proposed and adopted. The SDT invites the commenter to submit a SAR to modify the standard with a proposed definition.				

Voter	Entity	Segment	Vote	Comment
Thomas J. Bradish	Reliant Energy Services	5	Negative	Reliant votes "no" on the Manitoba interpretation. If a Special Protection System ("SPS") is fully redundant it is likely for good reason; namely, if one side fails the SPS remains functional. Therefore, the degree to which the operationally-intended, full redundancy of a SPS has been "compromised," "limited" or otherwise "reduced" is the degree to which it has been "degraded." Semantics aside, and at a minimum, off-nominal SPS operating states should be appropriately reported.
Trent Carlson	Reliant Energy Services	6	Negative	If a Special Protection System ("SPS") is fully redundant it is likely for good reason; namely, if one side fails the SPS remains functional. Therefore, the degree to which the operationally-intended, full redundancy of a SPS has been "compromised," "limited" or otherwise "reduced" is the degree to which it has been "degraded." Semantics aside, and at a minimum, off-nominal SPS operating states should be appropriately reported.
Response: The interpretation question is about operations of the system, i.e, is the operation of the power system compromised? Loss of full redundancy may be a fact, but if the system can continue to operate using alternate, albeit temporary, procedures then there is no mandate to call the Reliability Coordinator. (Though there is no mandate to report, it does not mean the TOP is prohibited from reporting.) If the system is at risk, then yes the TOP is mandated to report the conditions. In short, the issue is not redundancy but operational integrity. The commenter is invited to submit a SAR regarding off-nominal operating states.				
Martin Bauer	U.S. Bureau of Reclamation	5	Affirmative	The response provided infers that the communication system is not considered a part of the SPS and therefore not subject to the IRO 005 reporting. It is not clear if that was the intent of the response. It would have been far better for the response to be explicit.
Response: An interpretation of a standard does not permit the creation of requirements or definitions. The question asked in the request had to do with the communications system. The interpretation strictly addresses the communications issue and is not intended to imply anything beyond the question posed.				
Guy Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	During the next revision to the standard, further clarity as to what constitutes a "degradation" for a SPS that would fall under the reporting requirements. Although this interpretation does clarify this issue, further clarification is desireable. There may be other types of degradation of a SPS that the industry be struggling with that may result in compliance issues and initiate repeals.
Response: Thank you. Your comment has been shared with the SDT working on Project 2007-05 (Balancing Authority Controls) for its consideration.				

Voter	Entity	Segment	Vote	Comment
Carter B. Edge	SERC Reliability Corporation	10	Negative	The interpretation declines to answer the question. I would vote to approve if the interpretation stopped there. Rather, it goes on to provide interpretations of several other requirements, which while associated with the request, do not in themselves answer the question. This appears to be an overly broad application of the interpretations process to the extent that the standards development process is undermined.
Response: The team respectfully disagrees with the premise that the interpretation doesn't answer the question or that it extends to other, unrelated requirements. Questions regarding the process may be directed to the NERC standards process manager.				
Louise McCarren	Western Electricity Coordinating Council	10	Negative	WECC agrees with the conclusion for IRO-005-1 but disagrees with the response that a definition for the term degraded is not needed for TOP-005. If an RC asks for information on new or degraded special protections systems, the TOP and BA are obligated to provide that information. Without a definition of what the term degraded means, the TOP and BA could be uncertain for which special protections schemes they need to send data to the RC.
Response: An interpretation of a standard does not permit the creation of requirements or definitions. Absent a specific definition of the term degraded, the SDT provided its subjective evaluation of the intent of the word. As stated in the interpretation, the SDT has no objection to a formal definition being proposed and adopted. The SDT invites the commenter to submit a SAR to modify the standard with a proposed definition.				

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Standards Announcement

Recirculation Ballot Window Open
April 17–27, 2009

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Interpretation of TOP-005-1 and IRO-005-1 for Manitoba Hydro (Project 2008-18)

A recirculation ballot window for an interpretation of TOP-005-1 — Operational Reliability Information and IRO-005-1 — Reliability Coordination — Current Day Operations for Manitoba Hydro is now open **until 8 p.m. EDT on April 27, 2009**.

Project Background

Manitoba Hydro requested an interpretation of the meaning of the term "degraded/degradation" as used in NERC standards TOP-005-1 and IRO-005-1 and specifically, whether a Special Protection System that is operating with only one communication channel in service would be considered "degraded" for the purposes of these standards. The request and interpretation are posted on the project page: http://www.nerc.com/filez/standards/Project2008-18_Interpretation_TOP-005-1_IRO-005-1_ManitobaHydro.html

Recirculation Ballot Process

The Standards Committee encourages all members of the Ballot Pool to review the consideration of comments submitted with the initial ballots. In the recirculation ballot, votes are counted by exception only — if a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

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

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Standards Announcement

Final Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Interpretation of TOP-005-1 and IRO-005-1 for Manitoba Hydro (Project 2008-18)

The ballot pool approved the interpretation. The interpretation will be submitted to the NERC Board of Trustees for adoption.

The recirculation ballot for an interpretation of TOP-005-1 — Operational Reliability Information and IRO-005-1 — Reliability Coordination — Current Day Operations for Manitoba Hydro ended April 27, 2009. The final ballot results are shown below. The Ballot Results Web page provides a link to the detailed results.

Quorum: 95.56%
Approval: 92.81%

Ballot Criteria

Approval requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses.

Project Background

Manitoba Hydro requested an interpretation of the meaning of the term “degraded/degradation” as used in NERC standards TOP-005-1 and IRO-005-1 and specifically, whether a Special Protection System that is operating with only one communication channel in service would be considered “degraded” for the purposes of these standards.

The request and interpretation are posted on the project page:
http://www.nerc.com/filez/standards/Project2008-18_Interpretation_TOP-005-1_IRO-005-1_ManitobaHydro.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Ballot Results	
Ballot Name:	Project 2008-18 Interpretation-Manitoba Hydro_rc
Ballot Period:	4/17/2009 - 4/27/2009
Ballot Type:	recirculation
Total # Votes:	215
Total Ballot Pool:	225
Quorum:	95.56 % The Quorum has been reached
Weighted Segment Vote:	92.81 %
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.	63	1	53	0.946	3	0.054	2	5
2 - Segment 2.	9	0.8	8	0.8	0	0	0	1
3 - Segment 3.	57	1	49	0.961	2	0.039	3	3
4 - Segment 4.	12	1	11	1	0	0	1	0
5 - Segment 5.	45	1	36	0.9	4	0.1	5	0
6 - Segment 6.	25	1	21	0.875	3	0.125	0	1
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	2	0.2	2	0.2	0	0	0	0
9 - Segment 9.	3	0.3	3	0.3	0	0	0	0
10 - Segment 10.	9	0.9	7	0.7	2	0.2	0	0
Totals	225	7.2	190	6.682	14	0.518	11	10

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Jason Shaver	Affirmative	View
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney	Affirmative	
1	Baltimore Gas & Electric Company	John J. Moraski	Affirmative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	

1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Alan L Cooke	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dominion Virginia Power	William L. Thompson		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S. LLC	Larry Monday	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	Farmington Electric Utility System	Alan Glazner	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
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	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Kissimmee Utility Authority	Joe B Watson	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	National Grid	Manuel Couto	Affirmative	
1	New Brunswick Power Transmission Corporation	Brian Scott		
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	View
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Abstain	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Alan Derichsweiler	Negative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	

3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	View
3	American Electric Power	Raj Rana	Negative	View
3	Arizona Public Service Co.	Thomas R. Glock	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	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost		
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	View
3	Florida Power & Light Co.	W. R. Schoneck	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Georgia System Operations Corporation	Edward W Pourciau	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Abstain	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Jamie Hall	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Michael Lupo	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	View
3	PECO Energy an Exelon Co.	John J. McCawley	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	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	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Affirmative	View
3	Tampa Electric Co.	Ronald L. Donahey		
3	Turlock Irrigation District	Casey Hashimoto	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	

4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	Amerenue	Sam Dwyer	Negative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Affirmative	View
5	City of Tallahassee	Alan Gale	Affirmative	
5	Cleco Power LLC	Grant Bryant	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Dynegy	Greg Mason	Affirmative	
5	Electric Power Supply Association	Jack R. Cashin	Abstain	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	FPL Energy	Benjamin Church	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Northern States Power Co.	Liam Noailles	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	PacifiCorp Energy	David Godfrey	Affirmative	View
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Thomas Piascik	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Negative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Abstain	
5	Southeastern Power Administration	Douglas Spencer	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	Frank L Busot	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Negative	
5	Tennessee Valley Authority	Frank D Cuzzort	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	View
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Kansas City Power & Light Co.	Thomas Saitta	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	PacifiCorp	Gregory D Maxfield	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Reliant Energy Services	Trent Carlson	Negative	View
6	Salt River Project	Mike Hummel		

6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Southern California Edison Co.	Marcus V Lotto	Affirmative	
6	Tampa Electric Co.	Heidi Giustiniani	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	View
10	Southwest Power Pool	Charles H Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

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Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

Exhibit D

Roster of the Interpretation Development Team

RFI of TOP-005-1 and IRO-005-1 by Manitoba Hydro — Project 2008-18		
Chairman	James S. Case — Manager, Transmission Security Coordination	Entergy Services, Inc.
Vice Chairman	Karl Tammar	Northeast Utilities
	Paul Bleuss — Lead California/Mexico Reliability Coordinator	California/Mexico Reliability Coordinator (CMRC)
	Albert DiCaprio — Strategist	PJM Interconnection, L.L.C.
	Ryan Johnson	NRG Energy Power Marketing, Inc.
	Phillip Lavallee	National Grid USA
	Jason L. Marshall, P.E. — Technical Manager, Standards Compliance and Strategy	Midwest ISO, Inc.
	H. Steven Myers — Manager of Operating Standards	Electric Reliability Council of Texas, Inc.
	Paul Olson — Senior Power System Operator	Sacramento Municipal Utility District
	James Useldinger — Manager, T&D System Operations	Kansas City Power & Light Co.
	Gregory Van Pelt	California ISO
NERC Staff Coordinator	Edward J. Dobrowolski — Standards Development Coordinator	North American Electric Reliability Corporation
NERC Staff	Maureen E. Long — Standards Process Manager	North American Electric Reliability Corporation