



June 8, 2011

**VIA ELECTRONIC FILING**

Kirsten Walli, Board Secretary  
Ontario Energy Board  
P.O Box 2319  
2300 Yonge Street  
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Re: *North American Electric Reliability Corporation*

Dear Ms. Walli:

The North American Electric Reliability Corporation (“NERC”) hereby submits this petition seeking approval of proposed Regional Reliability Standard PRC-002-NPCC-01 — Disturbance Monitoring, and two associated new definitions included below and set forth in **Exhibit A** to this petition:

**Current Zero Time** — The time of the final current zero on the last phase to interrupt.

**Generating Plant** — One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

These proposed terms will be added to the NERC Glossary of Terms as applicable only to entities in the Northeast Power Coordinating Council (“NPCC”) footprint.

The proposed Regional Reliability Standard and defined terms were approved by the NERC Board of Trustees during its November 4, 2010 meeting. NERC requests the standard and defined terms become effective upon the first day of the first calendar quarter following approval.

This petition consists of the following:

- this transmittal letter;
- a table of contents for the entire petition;
- a narrative description providing justification for the proposed Regional Reliability Standard;
- Regional Reliability Standard PRC-002-NPCC-01 — Disturbance Monitoring and Implementation Plan, submitted for approval (**Exhibit A**);
- the NERC Board of Trustees' Resolution approving PRC-002-NPCC-01 — Disturbance Monitoring and directing it be filed with the applicable governmental authorities (**Exhibit B**);
- the complete Development Record of the proposed Regional Reliability Standard (**Exhibit C**);
- the Standard Drafting Team roster (**Exhibit D**); and
- the Violation Severity Level and Violation Risk Factor Guideline Analysis (**Exhibit E**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Andrew M. Dressel

Andrew M. Dressel

Attorney for North American Electric  
Reliability Corporation

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**BEFORE THE  
ONTARIO ENERGY BOARD  
OF THE PROVINCE OF ONTARIO**

**NORTH AMERICAN ELECTRIC )  
RELIABILITY CORPORATION )**

**PETITION OF THE  
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION  
FOR APPROVAL OF PROPOSED NPCC REGIONAL RELIABILITY  
STANDARD PRC-002-NPCC-01 — DISTURBANCE MONITORING**

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June 8, 2011

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## TABLE OF CONTENTS

|   |    |
|---|----|
| I. Introduction   | 1  |
| II. Notices and Communications  | 2  |
| III. Background:  | 2  |
| a. Basis for Approval of Proposed Regional Reliability Standard   | 2  |
| IV. Justification for Approval of the Proposed Regional Reliability Standard  | 5  |
| a. Basis and Purpose of Standard PRC-002-NPCC-01 – Disturbance Monitoring   | 5  |
| b. Proposed Terms   | 6  |
| c. Demonstration that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest | 7  |
| d. Additional Criteria for Regional Reliability Standards   | 25 |
| V. Summary of the Regional Reliability Standard Development Proceedings   | 26 |
| VI. Conclusion  | 30 |
| <b>Exhibit A</b> — PRC-002-NPCC-01 — Disturbance Monitoring Regional Reliability Standard Proposed and Implementation Plan for Approval           |    |
| <b>Exhibit B</b> — The NERC Board of Trustees’ Resolution on the PRC-002-NPCC-01 — Disturbance Monitoring Regional Reliability Standard           |    |
| <b>Exhibit C</b> — Complete Development Record of Proposed PRC-002-NPCC-01 Disturbance Monitoring Regional Reliability Standard                   |    |
| <b>Exhibit D</b> — Standard Drafting Team Roster  |    |
| <b>Exhibit E</b> — PRC-002-NPCC-01 Violation Severity Level and Violation Risk Factor Analysis  |    |

## I. INTRODUCTION

The North American Electric Reliability Corporation (“NERC”) hereby requests approval of proposed Regional Reliability Standard, PRC-002-NPCC-01 and two associated new definitions, included in **Exhibit A**. The proposed Regional Reliability Standard includes two defined terms as follows:

**Current Zero Time** — The time of the final current zero on the last phase to interrupt.

**Generating Plant** — One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

These terms do not presently appear in the NERC Glossary of Terms, and they do not conflict with existing glossary terms.

The Regional Reliability Standard proposed will be in effect only for applicable registered entities within Northeast Power Coordinating Council Region (“NPCC”). NERC continent-wide Reliability Standards do not presently address the issues covered in this proposed Regional Reliability Standard.

On November 4, 2010 the NERC Board of Trustees approved PRC-002-NPCC-01 — Disturbance Monitoring. NERC requests approval of this Regional Reliability Standard, to be made effective upon approval. **Exhibit A** to this filing sets forth the proposed Regional Reliability Standard and Implementation Plan. **Exhibit B** is the NERC Board of Trustees’ resolution to approve the proposed Regional Reliability Standard. **Exhibit C** contains the complete record of development for the proposed Regional Reliability Standard. **Exhibit D** includes the standard drafting team roster. **Exhibit E** is the Violation Severity Level (“VSL”) and Violation Risk Factor (“VRF”) guideline analysis.

NERC filed the proposed PRC-002-NPCC-01 Regional Reliability Standard and associated documents with the Federal Energy Regulatory Commission (“FERC”), and is also submitting this filing with the other applicable governmental authorities in Canada.

## **II. NOTICES AND COMMUNICATIONS**

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

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## **III. BACKGROUND**

### **a. Basis for Approval of Proposed Regional Reliability Standard**

NPCC is not an “interconnection-wide” Regional Entity, and its standards are intended to apply only to that part of the Eastern Interconnection within the NPCC geographical footprint. As discussed in the *Northeast Power Coordinating Council, Inc. Regional Reliability Standard Development Procedure*,<sup>1</sup> NPCC’s standards are developed according to the following characteristic attributes:

- **Open** — The NPCC Regional Reliability Standards Development Procedure provides any person the ability to participate in the development of a

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<sup>1</sup> The *Northeast Power Coordinating Council, Inc. Regional Reliability Standard Development Procedure* is available at <http://www.npcc.org/regStandards/Overview.aspx>

standard. Any entity that is directly and materially affected by the reliability of the NPCC's Bulk Power System has the ability to participate in the development and approval of reliability standards. There are no undue financial barriers to participation. Participation in the open comment process is not conditional upon membership in the ERO, NPCC or any organization, and participation is not unreasonably restricted on the basis of technical qualifications or other such requirements. NPCC utilizes a website to accomplish this. Online posting and review of standards and the real time sharing of comments uploaded to the website allow complete transparency.

- **Inclusive** — The NPCC Regional Reliability Standards Development Procedure provides any person with a direct and material interest the right to participate by expressing an opinion and its basis, have that position considered, and appealed through an established appeals process if adversely affected.
- **Balanced** — The NPCC Regional Reliability Standards Development Procedure has a balance of interests and all those entities that are directly and materially affected by the reliability of the NPCC's Bulk Power System are welcome to participate and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter. This will be accomplished through the NPCC Bylaws defining eight sectors (categories) for voting.
- **Fair Due Process** — The NPCC Regional Reliability Standards Development Procedure provides for reasonable notice and opportunity for public comment. The procedure includes public notice of the intent to develop a standard, a 45 calendar day public comment period on the proposed standard request, or standard with due consideration of those public comments, and responses to those comments will be posted on the NPCC website. A final draft will be posted for a 30 calendar day pre-balloting period, and then a ballot of NPCC Members will be conducted. Upon approval by the NPCC Members, the NPCC Board then votes to approve submittal of the Regional Standard to NERC.
- **Transparent** — All actions material to the development of Regional Reliability Standards are transparent and information regarding the progress is posted on the NPCC website as well as through extensive email lists.

Proposed NPCC standards are subject to approval by NERC, as the ERO, and the applicable governmental authorities before becoming mandatory and enforceable. The NPCC Regional Reliability Standard was developed in an open, transparent, and inclusive fashion. During development of the standard, workshops were conducted jointly with other Regional Entities and NPCC members including Regional

Transmission Organizations as well as state regulators. The proposed standard is widely supported by the NPCC ballot body and regulatory agencies that see this as a meaningful and necessary step forward in solving a longstanding problem. The standard was reviewed by NPCC legal counsel for consistency with the provisions and stated goals of the applicable governmental requirements. As a condition of NPCC membership, all NPCC Members<sup>2</sup> agree to adhere to the NERC Reliability Standards in addition to the NPCC Regional Reliability Standards. NERC Reliability Standards and the NPCC Regional Reliability Standards are both enforced through the NPCC Compliance Program.

As previously noted, NPCC is a Regional Entity, but is not organized on an Interconnection-wide basis. Therefore, NERC is not required to rebuttably presume the proposed standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The proposed Regional Reliability Standard was developed using the *Northeast Power Coordinating Council, Inc. Regional Reliability Standard Development Procedure*<sup>3</sup> that enables all parties with an interest in the standard to participate in its development. NERC's public posting of this proposed Regional Reliability Standard did not elicit any significant technical objection. NERC determined that the proposed standard meets the criteria for consideration and approval as a Regional Reliability Standard.

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<sup>2</sup> As defined in Section IV.B of the NPCC Corporation By-laws. Available at: <http://www.npcc.org/documents/aboutus/BusPlanBylaws.aspx>.

<sup>3</sup> The Northeast Power Coordinating Council, Inc. *Regional Reliability Standard Development Procedure*. Available at <http://www.npcc.org/regStandards/Overview.aspx>.

#### **IV. JUSTIFICATION FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD**

This section summarizes the development of the proposed Regional Reliability Standard PRC-002-NPCC-01 — Disturbance Monitoring; describes the reliability objectives to be achieved by the Regional Reliability Standard; explains the development history of the Regional Reliability Standard; and demonstrates how the standard is just and reasonable. NERC, in its analysis and approval of the proposed Regional Reliability Standard, determined that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

The complete development record for the proposed Regional Reliability Standard is provided in **Exhibit C** and includes the development and approval process, comments received during the industry-wide comment period, responses to those comments, ballot information, and NERC’s evaluation of the proposed standard.

##### **a. Basis and Purpose of Standard PRC-002-NPCC-01 — Disturbance Monitoring**

The proposed regional standard, PRC-002-NPCC-01 — Disturbance Monitoring, is designed to ensure that adequate disturbance data is available to facilitate Bulk Electric System (“BES”) event analyses. PRC-002-NPCC-01 addresses the adequacy and security components of reliability by requiring that Disturbance Monitoring Equipment (“DME”) be available to monitor the BPS System response to disturbances. The BPS is subject to Faults or Disturbances, and scheduled and unscheduled outages which can range from transient faults on transmission lines to forced System Element outages. The event analysis data obtained through implementation of this standard will be used to better design and operate the BPS to withstand System disturbances which may cross

state and international boundaries. Investigation of each incident and application of any lessons learned is critical to optimize the performance of Protection Systems with the goal of preventing future incidents from becoming wide-area disturbances. The tools required to perform post-incident analyses include DME which can capture pre-event, event, and post-event conditions with a high degree of accuracy.

The proposed standard contains 17 requirements that establish Disturbance Monitoring for entities within the NPCC region. The proposed standard is included in **Exhibit A** to this filing.

#### **b. Proposed Terms**

NPCC is proposing the addition of two new terms to the NPCC Glossary of Terms: “Current Zero Time” and “Generating Plant”. These terms do not presently appear in the NERC Glossary of Terms, and they do not conflict with existing terms. NPCC determined that it was necessary to define “Current Zero Time” because Fault recording capability should be able to determine the precise time of circuit interruption. This precise time could only be clarified by adding a new defined term; thus, adding clarity to the Fault recording requirements.

Likewise, NPCC determined that it was necessary for clarity to define “Generating Plant.” The “Generating Plant” definition was created to address the need to clarify the sequence of event recording capability in Requirement R1 and the fault recording capability requirement in Requirement R4. One fault recorder is able to capture all the information from a single contingency affecting all the generators at a “Generating Plant” at a single physical location. Therefore it is more efficient to use just

one piece of DME since multiple DMEs at the same physical location would record the same information.

- c. Demonstration that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest**

**1. Proposed Reliability Standard is be designed to achieve a specified reliability goal**

The proposed Regional Reliability Standard, PRC-002-NPCC-01 — Disturbance Monitoring, is designed to ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses. PRC-002-NPCC-01 addresses the adequacy and security components of reliability by requiring the functional entities to provide the equipment to monitor the BES response to System disturbances as well as scheduled and unscheduled System outages. The analysis that this information supports will be used to better design and operate the BES to withstand and mitigate scheduled and unscheduled outages as well as System disturbances. PRC-002-NPCC-01 — Disturbance Monitoring contains 17 requirements that identify the proper locations for installation of Sequence of Events (“SOE”) recorders, Fault recorders, and DDRs; the equipment to be monitored; and the data to be captured by this equipment.

**2. Proposed Reliability Standard is applicable to users, owners, and operators of the bulk power system, and not others.**

The proposed Regional Reliability Standard is only applicable to Transmission Owners, Generator Owners, and Reliability Coordinators within the NPCC region. These entities are users, owners, or operators of the BPS.

### **3. Proposed Reliability Standard considers any other relevant factors.**

All comments and concerns were addressed using the *Northeast Power Coordinating Council Standards Development Procedure* which is consensus-based, technically sound, and open to the public and bordering entities that may be impacted by a Regional Reliability Standard. No other factors were identified as necessary for consideration by the standard drafting team in the development of the proposed Regional Reliability Standard.

### **4. Proposed Reliability Standard contains a technically sound method to achieve the goal.**

The proposed Regional Reliability Standard contains a technically sound means to achieve this goal.

In order to properly analyze an event on the BPS, it is important to know the relative changes in circuit breaker status, control, and protection signals. SOE recorders capture the equipment and Protection System sequence of events for monitored changes of state occurring in substations, switchyards, or power plants. With this information, Fault clearing times can be determined and Protection System and BPS behaviors during the event be more accurately evaluated. This information is used in conjunction with records from Fault recorders and DDRs to complete post-event analyses. For non-Fault conditions, the SOE record may be the only recorded data available.

PRC-002-NPCC-01 — Disturbance Monitoring Requirement R1 requires that each Transmission Owner and Generator Owner provide SOE recording capability by installing SOE recorders or as part of another device, such as Supervisory Control And Data Acquisition (“SCADA”), a Remote Terminal Unit (“RTU”), a generator plant Digital (or Distributed) Control System (“DCS”) or part of Fault recording equipment.

The capability must be provided at all substations and at locations where circuit breaker operation could affect continuity of service to radial Loads greater than 300MW, initiate drops 50MVA or more from the nameplate Rating or greater of a Generation unit, or create a Generation/Load island. SOE recording capability must also be provided at generating units above 50MVA nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA nameplate Capacity, and at Generating Plants above 300MVA nameplate Capacity (part 1.1). At each of the locations specified in part 1.1 the recorders must monitor Transmission and Generator circuit breaker positions (part 1.2.1), Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1 (part 1.2.2), and Teleprotection keying and receipt (part 1.2.3). The purpose of event analysis is not only to find out what causes an event, but also how the System responded and evolved during the event. Knowing the status change of generators during a BES event greatly helps protection engineers to understand how a System event developed and to prepare for future events.

The 300MW radial Load was selected for inclusion as the baseline for Requirement part 1.1 based on the engineering judgment and operating experience of the NPCC members. This is also consistent with NPCC document *A-15 Disturbance Monitoring Equipment Criteria*,<sup>4</sup> and the possibility of the loss of 300MW escalating to a wider area disturbance. Furthermore, the drafting team noted that the tripping of a fully loaded 1200 Amp 138kV circuit breaker would drop 300MW of load.

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<sup>4</sup> *Disturbance Monitoring Equipment Criteria* NPCC Document A-15 (2007). Available at: <http://www.npcc.org/documents/regStandards/Criteria.aspx>.

Ideally, every generator registered in NPCC should be monitored. However, this would require a tremendous commitment of resources. As a compromise, the drafting team decided that it would only be necessary to monitor significant generation sources with Capacities of at least 50 MVA for a single unit and 300 MVA for a Generating Plant. The drafting team set these limits after evaluating the relative contributions of the smaller and the larger generators to System events, and deciding that monitoring these larger generating units would provide more important and useful information for event analysis. Subject matter experts outside of the drafting team were also consulted to help arrive at these thresholds. The loss of a particular single generator might not cause a System-wide reliability concern, but there was concern that losing a cluster of generators due to a local disturbance could cause widespread impact. These generation thresholds are consistent with the existing NPCC document A-15 Disturbance Monitoring Equipment Criteria.

In reporting circuit outages for Wide Area Disturbances, the most precise time to use for the circuit interruption is Current Zero Time. The Current Zero Time is the time of fault clearing when the current in the last monitored phase goes to zero. Fault recording capability is necessary to determine the Current Zero Time for the loss of BPS Elements.

Fault recorders electronically store System waveforms and can be used to reproduce those System waveforms to analyze transients and abnormalities in System frequency. Requirement R2 of the proposed Regional Reliability Standard requires each Transmission Owner to provide Fault recording capability for: all transmission lines (part 2.1), autotransformers or phase-shifters connected to buses (part 2.2), shunt capacitors,

shunt reactors (part 2.3), individual generator line interconnections (part 2.4), Dynamic VAR Devices (part 2.5), and HVDC terminals (part 2.6) at facilities where Fault recording equipment is required to be installed as per R3.

Another critical piece of information in post Fault analysis is the Fault duration, and that time is provided by the Fault recorders. Requirement R3 of the proposed standard requires that each Transmission Owner have Fault recording capability that determines the Current Zero Time for loss of BES transmission Elements.

Requirement R4 of the proposed standard requires that each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (“GSU”) transformer to a BES Element unless Fault recording capability is already provided by the Transmission Owner. Because of the importance of the data captured by Fault recorders, this requirement ensures that all BES facilities will be monitored. Using the 200 MVA threshold for fault capability captures sufficient fault waveforms from all generation sources that are connected to BPS buses. Additionally, it is also consistent with the 200 MVA threshold stipulated in NPCC document A-15 Disturbance Monitoring Equipment Criteria. Moreover, the requirement recognizes that a duplication of equipment monitoring the same quantities is not needed.

Because there are certain electrical quantities that must be known and processed for post event analysis, it is necessary to record these quantities. Requirement R5 of the proposed standard requires that each Transmission Owner and Generator Owner record for Faults sufficient electrical quantities for each monitored Element to determine: three phase-to-neutral voltages (common bus-side voltages may be used for lines) (part 5.1),

three phase currents and neutral currents (part 5.2), polarizing currents and voltages, if used (part 5.3), frequency (part 5.4), and Real and Reactive Power (part 5.5).

Voltage is a necessary quantity needed for post event analysis. Ideally, monitoring all three phases eliminates the need for calculating an unmonitored phase voltage quantity. Three phase to neutral voltages are suggested because they serve as a check of the health of the voltage sources and are needed because the voltage sources may be used to supply protective relays. Monitoring three of the four voltage quantities (three phases and neutral) allows for the calculation of the unmonitored quantity.

Current, like voltage, is a necessary quantity needed for post event analysis. Monitoring all three phases also eliminates the need for the uncertainty in calculating an unmonitored current. Monitoring all three phase currents are specified because they serve as a check of the health of the current sources (current transformers), because the current sources may be used to supply protective relays. Monitoring three of the four current quantities allows for the calculation of the unmonitored quantity. Monitoring polarizing currents and voltages, if used, provides an additional quantity for post event analysis. Monitoring polarizing currents and voltages monitors the health of the current and voltage sources during Fault conditions. Monitoring frequency is important to analyze generator performance during events, and any resonances and transients that might be caused by a Disturbance. Finally, monitoring Real and Reactive Power provides data that can be used to satisfy the power transfer equation during post event analysis, and a power System's response and contribution to an event.

When recording the monitored data, it is necessary for the equipment to have the capability to capture the intended information with enough detail to make it meaningful.

Requirement R6 of the proposed standard requires that each Transmission Owner and Generator Owner provide Fault recording with the specific capabilities in parts in 6.1 through 6.4. Part 6.1 specifies that Fault recorders record duration be a minimum of one (1) second. The one second specification for record duration allows for the capture of a transient, a time stamp, the requirements of local relays for reproducing events in the relays, and the expected local clearing time for Faults. Part 6.2 specifies that Fault recorders must have a minimum recording rate of 16 samples per cycle. This minimum recording rate was selected to accommodate existing recording equipment, and sufficiently captures the data that is required for post event analysis. Part 6.3 specifies that Fault recorders be set to trigger for at least: monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups (part 6.3.1), neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current (part 6.3.2), or monitored phase undervoltage set at 0.85 pu or greater (part 6.3.3). Analog and digital triggers are used to initiate and optimize the recording of System Faults, Protective Relay performance, and abnormal System conditions by recognizing System abnormalities.

DDRs record power System behavior for incidents where the power System experiences dynamic events such as low frequency oscillations (0.1 Hz to 3 Hz), or abnormal frequency or voltage excursions. This information is necessary for comprehensive post-event analysis. The locations of DDRs can be selected with the help of time-domain simulation or small signal analysis to help identify the most critical substations where local and inter-area power System dynamics can be monitored. By combining time-domain dynamic simulation and linear based small signal analysis,

critical sites can be identified for a DDR. DDRs should be well distributed across the NPCC Region. Requirement R7 requires that each Reliability Coordinator establish its area's requirements for DDR capability that: provides a minimum of 1 DDR per 3,000 MW of peak Load (part 7.1); and records dynamic disturbance information with consideration of (part 7.2) major Load centers (part 7.2.1), major Generation clusters (part 7.2.2), major voltage sensitive areas (part 7.2.3), major transmission interfaces (part 7.2.4), major transmission junctions (part 7.2.5), Elements associated with Interconnection Reliability Operating Limits (IROLs) (part 7.2.6), and major EHV interconnections between operating Areas (part 7.2.7).

Requirement R8 requires that each Reliability Coordinator specify that DDRs installed, after the approval of this standard, function as continuous recorders. The DDRs currently available are continuous recorders.

To adequately capture System disturbance data, DDRs need certain capabilities. Requirement R9 requires that each Reliability Coordinator specify that DDRs are installed with the specific capabilities detailed in parts 9.1 through 9.3. Part 9.1 specifies that DDRs must have a minimum recording time of sixty (60) seconds per trigger event. Sixty second record lengths allow the capture of enough information to enable evaluation of System performance. Part 9.2 requires that DDRs have a minimum data sample rate of 960 samples per second and a minimum data storage rate for RMS quantities of six (6) data points per second. Available DDRs have the capability to meet and exceed this requirement. Sample rates at or above 960 samples per second will provide enough information for a thorough post event analysis. Part 9.3 specifies that each DDR shall be set to trigger for at least one of the following (based on the manufacturers' equipment

capabilities): rate of change of frequency (part 9.3.1), rate of change of Power (part 9.3.2), delta frequency (recommend 20 mHz change) (part 9.3.3), and oscillation of frequency (part 9.3.4).

As previously stated, it is necessary for the equipment to capture the monitored data with enough detail to make it meaningful for post event analysis. Requirement R10 requires that each Reliability Coordinator establish requirements such that the quantities detailed in parts 10.1 through 10.5 are monitored or derived where DDRs are installed. Part 10.1 specifies that line currents for most lines such that normal line maintenance activities do not interfere with DDR functionality. Current needs to be recorded during abnormal System events to determine overloads, System and fault impedances, transients, and System performance. It is important that the design of the input circuitry to the DDR have the current sources not affected by normal line maintenance activities to maximize the DDR's in service time. Part 10.2 specifies that bus voltages such that normal bus maintenance activities do not interfere with DDR functionality. Voltage needs to be recorded during an abnormal System event to determine System impedances, transients, and System reactive parameters. It is important that the design of the input circuitry not have the voltage sources affected by normal line maintenance activities to maximize the DDR's in service time. Part 10.3 specifies that as a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements be monitored or derived. One of the monitored voltages shall be of the same phase as the monitored current. Stability simulations assume that the post-fault response of a power System is balanced in the three phases. Therefore monitoring one phase current provides satisfactory results. Part 10.4 specifies that frequency be monitored or derived.

Frequency needs to be monitored to determine the generation/load, balance/unbalance, and to record any transients. Part 10.5 specifies that real and reactive power be monitored or derived. This is a parameter that can be derived from the monitored quantities to enable an accurate analysis of System performance for abnormal events.

It is important that the RE know what data will be recorded for a System disturbance. As a result, Requirement R11 requires that each Reliability Coordinator document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the RE upon request.

The drafting team determined that the Reliability Coordinator shall be responsible for ensuring that adequate data is captured for event analysis. Requirement R12 mandates that each Reliability Coordinator specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners.

Because it is necessary to coordinate expectations for the installation and the capability of equipment, the Reliability Coordinators, Transmission Owners, and Generator Owners must discuss and implement realistic implementation schedules. That is, to ensure that all the necessary data needed to analyze an event is captured, the Reliability Coordinators, Transmission Owners, and Generator Owners must know what they are each doing so as not to install unnecessarily redundant equipment. Requirement R13 requires that each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR to acquire and install the DDR in

accordance with Requirement R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule.

To ensure the that the equipment required by this standard is available and functioning properly, Requirement R14 requires that each Transmission Owner and Generator Owner establish a maintenance and testing program for stand-alone DME (equipment whose only purpose is disturbance monitoring) that includes: maintenance and testing intervals and their basis (part 14.1); a summary of maintenance and testing procedures (part 14.2); monthly verification of communication channels used for accessing records remotely (part 14.3); monthly verification of time synchronization (part 14.4); monthly verification of active analog quantities (part 14.5); verification of DDR and Digital Fault Recorder (“DFR”) settings in the software every six (6) years (part 14.6); and a requirement to return failed units to service within 90 days (part 14.7). Part 14.7 further specifies that if a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.

For coordination purposes the standard drafting team designed a requirement to ensure that all appropriate parties have access to data in a timely fashion. Requirement R15 requires that each Reliability Coordinator, Transmission Owner, and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner must provide recorded disturbance data from DMEs within 30 days of receipt of the request as specified in parts 15.1 and 15.2.

To facilitate post event analysis, it is important to share information in acceptable and compatible formats to ensure accurate and timely analysis. Requirement R16

requires that each Reliability Coordinator, Transmission Owner, and Generator Owner submit the data files conforming to the format requirements in parts 16.1 through 16.3.

Finally, Requirement R17 requires that each Reliability Coordinator, Transmission Owner, and Generator Owner maintain, record and provide to the RE, upon request, specific types of data for the DMEs installed to meet this standard. This will facilitate the post event analysis.

**5. Proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply.**

The proposed Regional Reliability Standard establishes clear and unambiguous requirements for Transmission Owners, Generator Owners, and Reliability Coordinators within the NPCC region as discussed above. Transmission Owners, Generator Owners, and Reliability Coordinators in the NPCC region are clearly identified as the functional entities responsible for the actions specified in the requirements. The Transmission Owners and Generator Owners are assigned requirements related to the installation of DME and are responsible for ensuring that the equipment captures the specific data at the locations specified in the proposed standard. The Reliability Coordinators are assigned the responsibility of determining the DDR requirements and for coordinating these requirements with the Regional Entity as well as the Transmission Owners and Generator Owners. Additionally, all of the data generated through the disturbance monitoring performed under this standard shall be available upon request by the ERO, the RE, or other Transmission Owners or Generator Owners in an approved format.

**6. Proposed Reliability Standard includes clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation**

The proposed Regional Reliability Standard includes a Violation Risk Factor (“VRF”) and Violation Severity Level (“VSL”) for each requirement. The ranges of penalties for violations will be based on the applicable VRF and VSL and will be administered based on the sanctions table and supporting penalty determination process described in the NERC Sanction Guidelines.<sup>5</sup>

NPCC developed the VSLs and VRFs proposed for assignment to PRC-002-NPCC-01 following applicable NERC guidance. **Exhibit E** to this filing contains the VSL and VRF guideline analysis for PRC-002-NPCC-01.

**7. Proposed Reliability Standard identifies clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.**

Each requirement of PRC-002-NPCC-01 has an associated measure of compliance that will assist those enforcing the standard in enforcing it in a consistent and non-preferential manner. The proposed measures are as follows:

- M1.** Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Sequence of Event recording capability in accordance with 1.1 and 1.2. (R1)
- M2.** Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 2.1 to 2.6. (R2)
- M3.** Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability that determined the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements in accordance with R3.
- M4.** Each Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability for its Generating Plants at and above 200 MVA Capacity in accordance with R4.

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<sup>5</sup> NERC Rules of Procedure Appendix 4B. Available at: [http://www.nerc.com/files/NERC\\_Rules\\_of\\_Procedure\\_EFFECTIVE\\_20110101.pdf](http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110101.pdf).

- M5.** Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it records for Faults, sufficient electrical quantities for each monitored Element to determine the parameters listed in 5.1 to 5.5. (R5)
- M6.** Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 6.1 to 6.4. (R6)
- M7.** Each Reliability Coordinator shall have, and provide upon request, evidence that it established its area's requirements for Dynamic Disturbance Recording (DDR) capability in accordance with 7.1 and .2. (R7)
- M8.** Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs installed after the approval of this standard function as continuous recorders. (R8)
- M9.** Each Reliability Coordinator shall have, and provide upon request, evidence that it developed DDR setting triggers to include the parameters listed in 9.1 to 9.3. (R9)
- M10.** Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs monitor the Elements listed in 10.1 through 10.5. (R10)
- M11.** Each Reliability Coordinator shall have, and provide upon request, evidence that it documented additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10. (R11)
- M12.** Each Reliability Coordinator shall have, and provide upon request, evidence that it specified its DDR requirements which included the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners in the Reliability Coordinator's area. (R12)
- M13.** Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it acquired and installed the DDRs in accordance with the specifications contained in the Reliability Coordinator's request, and a mutually agreed upon implementation schedule. (R13)
- M14.** Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it has a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that meets the requirements in 14.1 through 14.7. (R14)
- M15.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided recorded disturbance data from DMEs within 30 days of the receipt of the request from the entities listed in 15.1 and 15.2. (R15)
- M16.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it submitted the data files in a format that meets the requirements in 16.1 through 16.3. (R16)

**M17.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it maintained a record of and provided to NPCC when requested, the data on DMEs installed meeting the requirements 17.1 through 17.8. (R17)

**8. Proposed Reliability Standard achieves a reliability goal effectively and efficiently — but does not necessarily have to reflect “best practices” without regard to implementation cost.**

Regional Reliability Standard PRC-002-NPCC-01 achieves its reliability goal effectively and efficiently. The standard accomplishes the reliability goal of ensuring the installation of adequate DME to capture data for BPS events occurring in the NPCC region. By facilitating event analysis, system reliability is improved by allowing effective real time responses to events, as well as improving system operations and designs to improve system performance. The Implementation Plan for PRC-002-NPCC-01 recognizes the existence of equipment already in place. Any additional costs for the installation of required equipment are necessary to ensure that adequate disturbance monitoring equipment is in place to capture System data for event analysis. The Implementation Plan and standard also recognize that certain disturbance monitoring functions are or can be incorporated into some types of existing equipment.

**9. Proposed Reliability Standard is not “lowest common denominator,” i.e., does not reflect a compromise that does not adequately protect bulk power system reliability.**

This proposed Regional Reliability Standard does not reflect a “lowest common denominator” approach. PRC-002-NPCC-01 achieves its reliability goal of capturing needed data for event analysis in an efficient and effective manner. The proposed standard PRC-002-NPCC-01 builds upon the NERC Board approved standard PRC-002-1 — Define Regional Disturbance Monitoring and Reporting Requirements and the Standard PRC-018-1 — Disturbance Monitoring Equipment Installation and Data

Reporting by proposing requirements that are more stringent than or are not covered by the existing standards as discussed above.

**10. Proposed Reliability Standard considers costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability.**

As discussed above, the proposed Implementation Plan recognizes the existence of DME already in place. Any costs incurred by the registered entities for the installation of additional equipment are necessary to ensure that adequate System data is captured for event analysis. The Implementation Plan and standard also recognize that certain disturbance monitoring functions can be incorporated into some types of existing equipment. By virtue of their electrical “size,” smaller entities will incur less expenses meeting the equipment requirements of this standard than larger entities.

**11. Proposed Reliability Standard is designed to apply on a regional basis and will only apply to the NPCC region.**

The proposed Regional Reliability Standard is designed on a regional basis and will only apply to the NPCC region. It is not intended to be applied throughout North America.

**12. Proposed Reliability Standard causes no undue negative effect on competition or restriction of the grid.**

This proposed Regional Reliability Standard does not cause undue negative effects on competition or restriction of the grid. Because this standard will be applied equally across the NPCC region, PRC-002-NPCC-01 will not negatively affect competition, or restrict available transmission capability within the NPCC footprint.

### **13. The implementation time for the proposed Reliability Standard is reasonable.**

The Implementation Plan for the Regional Reliability Standard proposes a phased in implementation schedule as follows:

Within two (2) years of FERC and Canadian entities' approvals, entities shall be 50 percent compliant at facilities required to have DME capabilities by:

- a. Installing Sequence of Events (SOE) capability at 50 percent of the facilities that previously had no SOE capability (percent complete will be based on the number of facilities completed)
- b. Installing additional SOE capability to facilities with existing SOEs such that 50 percent of the total required capability is complete (percent complete will be based on the number of SOE points required)
- c. Installing Fault Recording capability at 50 percent of the facilities that previously had no Fault Recording capability (percent complete will be based on the number of facilities completed)
- d. Installing additional Fault Recording capability to facilities with existing Fault Recording capability such that 50 percent of the required capability is complete (percent complete will be based on the number of traces required)
- e. Installing Dynamic Disturbance Recording (DDR) capability at 50 percent of the facilities that previously had no DDR capability (percent complete will be based on the number of facilities completed versus those required by the Reliability Coordinator)
- f. Installing additional DDR capability to facilities with existing DDR capability such that 50 percent of the required capability is complete (percent complete will be based on the number of elements as required by the Reliability Coordinator)

Within three (3) years of FERC and Canadian entities' approvals, entities shall be 75 percent compliant at facilities required to have DME capabilities by:

- a. Installing SOE capability at 75 percent of the facilities that previously had no SOE capability (percent complete will be based on the number of facilities completed)
- b. Installing additional SOE capability to facilities with existing SOEs such that 75 percent of the total required capability is complete (percent complete will be based on the number of SOE points required)

c. Installing Fault Recording capability at 75 percent of the facilities that previously had no Fault Recording capability (percent complete will be based on the number of facilities completed)

d. Installing additional Fault Recording capability to facilities with existing Fault Recording capability such that 75 percent of the required capability is complete (percent complete will be based on the number of traces required)

e. Installing DDR capability at 75 percent of the facilities that previously had no DDR capability (percent complete will be based on the number of facilities completed versus those required by the Reliability Coordinator)

f. Installing additional DDR capability to facilities with existing DDR capability such that 75 percent of the required capability is complete (percent complete will be based on the number of elements as required by the Reliability Coordinator)

Within four (4) years of FERC and Canadian entities' approvals, all (100 percent) SOE, Fault Recording, and DDR capability shall be installed to satisfy the requirements of the standard.

The information submitted by NPCC supports the implementation schedule presented.

#### **14. The Reliability Standard development process was open and fair.**

NPCC develops Regional Reliability Standards in accordance with **Exhibit C** (*Regional Reliability Standard Development Procedure*) of its Regional Delegation Agreement with NERC. The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NPCC considers the comments of all stakeholders and an affirmative vote of the stakeholders and the NPCC Board of Directors are both required to approve a Regional Reliability Standard for submission to NERC and the applicable governmental authorities.

The proposed Regional Reliability Standard has been developed and approved by industry stakeholders using NPCC's *Regional Reliability Standards Development*

*Procedure* and was approved by the NPCC Board of Directors on February 9, 2010. The standard was subsequently presented to, and approved by the NERC Board of Trustees Nov. 4, 2010. Therefore, NPCC has utilized its standard development process in good faith and in a manner that is open and fair. No commenters disagreed with the open and fair implementation of the NPCC process.

**15. Proposed Reliability Standard balances with other vital public interests.**

Neither NERC nor NPCC believes there are competing public interests with the request for approval of this proposed Regional Reliability Standard. No comments were received that indicated the proposed standard conflicts with other vital public interests. Therefore it is not necessary to balance this Reliability Standard against any other competing public interests.

**d. Additional Criteria for Regional Reliability Standards**

NERC is also required by FERC's Order No. 672 to ensure that a Regional Reliability Standard satisfies additional criteria: "A regional difference from a continent-wide Reliability Standard must either be (1) more stringent than the continent-wide Reliability Standard including a regional difference that addresses matters the continent-wide Reliability Standard does not, or (2) a Regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System."<sup>6</sup> The proposed standard satisfies these additional criteria.

The existing NERC continent-wide standard, PRC-002-1 — Define Regional Disturbance Monitoring and Reporting Requirements,<sup>7</sup> applies only to Regional Reliability Organizations (now known as Regional Entities). The proposed standard,

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<sup>6</sup> Order No. 672 at P 291.

<sup>7</sup> NERC Standard PRC-002-1 — Define Regional Disturbance Monitoring and Reporting.

PRC-002-NPCC-01, establishes more stringent installation requirements for sequence of event recorders by identifying specific installation locations, and the equipment to be monitored in Requirement R1. The proposed standard also establishes more stringent installation requirements for Fault recording capability by identifying specific transmission and generation facilities where the equipment should be installed in accordance with Requirement R2 through R6. While the NPCC Regional Reliability Standard mirrors the NERC standard for identifying DDR quantities, the proposed standard also specifies DDR equipment triggering options and establishes reporting requirements for the Region.

The proposed standard, PRC-002-NPCC-01, establishes requirements that specify the locations where Transmission Owners and Generator Owners must install DME. The PRC-018-1 standard does not specify the locations but does require the installation of equipment according to the RRO requirements. The proposed standard also adds the Reliability Coordinator as a functional entity. Finally, the proposed PRC-002-NPCC-01 standard is more stringent than the continent-wide standard because it adds monthly verification steps and requires verification of DDR and DFR settings in the software every six years while the continent-wide standard does not.

Furthermore PRC-002-1 is not enforceable. Because of this, NPCC recognized a reliability gap relating to Disturbance monitoring and reporting and developed PRC-002-NPCC-01 to fill this gap.

## **V. SUMMARY OF THE REGIONAL RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS**

**NERC Evaluation:** On May 14, 2010, NPCC submitted the proposed Regional Reliability Standard for evaluation and approval to NERC in accordance with NERC's

*Rules of Procedure and Regional Reliability Standards Evaluation Procedure*<sup>8</sup> that was approved by NERC's Regional Reliability Standards Working Group. NERC provided its evaluation of the proposed PRC-002-NPCC-01 standard to NPCC on July 3, 2010, included as **Exhibit C**, after NERC concluded its 45-day posting of the standard. In this report, NERC expressed several concerns regarding the proposed Regional Reliability Standard. These concerns pertained to the use of certain terms in the proposed standard; to the development of Measures including examples of evidence; and proposed modifications to the Violation Severity Levels necessary to comport with FERC's VSL Guidelines. The VSL proposals also resulted in changes to the associated requirements in the standard. During the evaluation process, NERC also identified several additional concerns in the proposed standard that NPCC should consider addressing in a future revision of the standard, primarily concerning the development structure of the requirements. In response to NERC's concerns, NPCC modified the proposed VSLs to comport with FERC's VSL Guidelines and elected to consider the additional NERC comments during a future revision of the standard.

**Key Issues:** During the development of the proposed standard, the drafting team encountered three key issues. The industry expressed concern over: 1) the development of a continent-wide standard by NERC to address this issue; 2) the size of affected generating units/plants; and 3) the definition of Bulk Electric System.

The development of the proposed standard began in mid-2008 and was intended to complement the ongoing work at NERC revising PRC-002-1 and PRC-018-1 in *Project 2007-11: Disturbance Monitoring*. The proposed standard establishes

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<sup>8</sup> Regional Reliability Standards Evaluation Procedure, Version 1 (2009). Available at: [http://www.nerc.com/docs/sac/rrswg/NERC\\_Regional\\_Reliability\\_Evaluation\\_Procedure.pdf](http://www.nerc.com/docs/sac/rrswg/NERC_Regional_Reliability_Evaluation_Procedure.pdf).

requirements that are currently not covered by either the Board approved standard, PRC-002-1 — Define Regional Disturbance Monitoring and Reporting Requirements, or PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting. The Regional Reliability Standard was initiated with the intention of addressing a reliability need to specify regional requirements for the installation of Disturbance Monitoring Equipment. Furthermore, the proposed standard addresses a specific recommendation from the August 14, 2003 Blackout Final NERC Report.<sup>9</sup>

While the work with *Project 2007-11: Disturbance Monitoring* is in progress, it was not anticipated for completion until after the proposed PRC-002-NPCC-01 standard's projected completion date. As a result, the proposed standard both addresses the recommendations above and relieves the reliability need to establish DME requirements currently not covered in the existing NERC standards.

The second key issue encountered related to the size of generating units/plants in the proposed standard. Requirement R1 part 1.1 specifies that SOE capability:

Be provided by Generator Owners at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island.

Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity.

As discussed above, the 300MW radial load was selected based on the engineering judgment and operating experience of NPCC members and is consistent with

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<sup>9</sup> Recommendation 28, "Require use of time-synchronized data recorders," *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force (2004) at p.162. Available at: <http://www.nerc.com/docs/docs/blackout/ch7-10.pdf>.

NPCC document A-15 *Disturbance Monitoring Equipment Criteria*, and the possibility of the loss of 300MW escalating to a wider area disturbance. Additionally, the drafting team used as a baseline the event that tripping of a fully loaded 1200 Amp 138kV circuit breaker would drop 300MW of load. Ideally, every generator registered in NPCC should be monitored. Because of the relative contributions of the smaller and larger generators to System events, it was decided that monitoring the larger units would provide the more important and useful information for event analysis.

The third key issue identified during the development of the standard was the definition of the BES. The purpose section of the proposed standard states that: “All references to equipment and facilities herein unless otherwise noted will be to Bulk Electric System (BES) elements.” Industry commenters expressed concern that this would lead to confusion because NPCC uses the defined term “Bulk Power System.” NPCC resolved the concern by noting that FERC, in its Order No. 693, approved NERC’s definition of Bulk Electric System, and using it as the basis for applicability of PRC-002-NPCC-01 would be consistent with NERC and other regions’ standards as well as Section 215 of the FPA.

### **Violation Risk Factors and Violation Severity Levels**

The proposed Regional Reliability Standard contains both VRFs and VSLs. The VRFs and VSLs are assigned to the main requirements in the standard. The VRFs and VSLs for this standard were developed and reviewed for consistency with NERC and

FERC guidelines.<sup>10</sup> Analyses of the assigned VRFs and VSLs to this standard are included in **Exhibit E**.

## **VI. CONCLUSION**

For the reasons stated above, NERC respectfully requests approval of the proposed PRC-002-NPCC-01 Regional Reliability Standard, the associated proposed definitions, and the associated Implementation Plan included in **Exhibit A** to this filing. NERC requests that these approvals be made effective in accordance with the Implementation Plan for PRC-002-NPCC-01 included in **Exhibit A** to this filing.

Respectfully submitted,

*/s/ Andrew M. Dressel*

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<sup>10</sup> See *Order on Violation Risk Factors*, 119 FERC ¶ 61,145 (2007) and *Order on Violation Severity Levels Proposed by the Electric Reliability Organization*, 123 FERC ¶ 61,284 (2008).

## **EXHIBITS A – E**

(Available on the NERC Website at

[http://www.nerc.com/fileUploads/File/Filings/Attachments\\_PRC-002-NPCC.pdf](http://www.nerc.com/fileUploads/File/Filings/Attachments_PRC-002-NPCC.pdf))