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**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** R-41-13

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Mandatory Reliability Standards Assessment Report No. 6
by British Columbia Hydro and Power Authority
and the Determination of Reliability Standards for Adoption in British Columbia

BEFORE: L.F. Kelsey, Commissioner
C.A. Brown, Commissioner
N.E. MacMurchy, Commissioner
B.A. Magnan, Commissioner
D.M. Morton, Commissioner
R.D. Revel, Commissioner

December 12, 2013

O R D E R

WHEREAS:

A. Pursuant to section 125.2(2) of the *Utilities Commission Act* (Act) the British Columbia Utilities Commission (Commission) has exclusive jurisdiction to determine whether a "reliability standard" as defined in the Act, is in the public interest and should be adopted in British Columbia (BC);

B. Ministerial Order No. MO39 dated February 22, 2009, established a *Mandatory Reliability Standards (MRS) Regulation*, which prescribes the parties that are subject to reliability standards adopted under section 125.2(6) of the Act;

C. In order to facilitate the Commission's consideration of reliability standards, British Columbia Hydro and Power Authority (BC Hydro) is required under section 125.2(3) of the Act to review each reliability standard and provide the Commission with a report assessing:

(a) any adverse impact of the reliability standard on the reliability of electricity transmission in British Columbia if the reliability standard were adopted;

(b) the suitability of the reliability standard for British Columbia;

(c) the potential cost of the reliability standard if it were adopted; and

(d) any other matter prescribed by regulation or identified by order of the Commission;

D. The approach taken to evaluate reliability standards has not changed from that used in previous MRS Assessment Reports. In those reports, the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards were viewed as having two components. The first component determines applicability and mandates the types of activities that are required to maintain system reliability. As per Assessment Report No. 1 dated March 27, 2009, British Columbia Transmission Corporation (now BC Hydro) was of the view that this portion alone is the "reliability standard" contemplated in section 125.2 of the Act, and is therefore the only component of the reliability standard assessed by BC Hydro. The second component includes the compliance provisions, which are not assessed by BC Hydro;

E. To date, BC Hydro has acted as the Planning Authority/Planning Coordinator (PA/PC) for the BC Hydro asset footprint only. The PA/PC responsibilities for the province require clarification at this time;

F. On May 24 and September 30, 2013, BC Hydro filed MRS Assessment Report No. 6 and Addendum respectively, pursuant to section 125.2(3) of the Act, assessing nine revised reliability standards developed by NERC. BC Hydro subsequently submitted two errata to the Addendum (Errata). BC Hydro assessed the reliability standards excluding the accompanying compliance provisions. The nine revised reliability standards supersede existing reliability standards adopted in BC by Commission Orders G-67-09, G-167-10, G-162-11 and R-1-13;

G. MRS Assessment Report No. 6 included an assessment of five new or revised defined terms included in the NERC Glossary of Terms;

H. In MRS Assessment Report No. 6, Addendum and Errata, BC Hydro concluded that the nine revised reliability standards and the five glossary terms are suitable for adoption in BC;

I. BC Hydro recommended that the effective date for PRC-023-1, Requirement 3 be rescinded and that only those portions of PRC-023-2 that could be enforced without reliance on a PA/PC come into effect in BC at this time;

J. In this and previous Assessment Reports, BC Hydro evaluates the reliability standards adopted in the US by the Federal Energy Regulatory Commission (FERC) and enforceable in the US between December 1 and November 30 of the previous year (Assessment Period). In Assessment Report No. 6, BC Hydro proposes to follow a refined assessment process when evaluating reliability standards that have requirements with staged effective dates, if one or more requirements are not enforceable in the US within the Assessment Period;

K. Pursuant to subsection 125.2(5) of the Act, the Commission posted the MRS Assessment Report No. 6, the Addendum and Errata to MRS Assessment Report No. 6 on its website and, by Order R-30-13 dated July 25, 2013, directed BC Hydro to publish a Notice of MRS Assessment Report No. 6 and Process for Public Comments, and established the Regulatory Timetable for comments;

L. FortisBC Inc. submitted that its feedback is reflected in BC Hydro's Assessment Report No. 6 and Addendum and that the Company has no additional comments;

M. On November 12, 2013, the Commission issued Information Requests to BC Hydro and, on November 27, 2013, BC Hydro submitted its responses to the Commission;

N. Pursuant to section 125.2(6) of the Act, the Commission must adopt the reliability standards addressed in the report if the Commission considers that the reliablilty standards are required to maintain or achieve consistency in BC with other jurisdictions that have adopted the reliablity standards;

O. The Commission has reviewed and considered MRS Assessment Report No. 6, the Addendum and Errata, the reliability standards and terms assessed therein, as well as the responses to the Information Requests; and

P. The Commission considers the compliance provisions of the reliability standards helpful for compliance monitoring in BC and finds it appropriate to provide effective dates for entities to come into compliance with the reliability standards and glossary terms adopted in this Order.

NOW THEREFORE pursuant to subsections 125.2(3) and 125.2(6) of the *Utilities Commission Act*:

1. The Commission adopts the nine revised standards with effective dates in the table found in Attachment A to this Order. The effective dates for the standards are as laid out in the table found in Attachment A to this Order. Each standard to be superseded by a standard adopted in this Order shall remain in effect until the effective date of the standard superseding it.

2. As a result of this Order and Orders G-67-09, G-167-10, G-162-11, G-175-11, R-1-13 and R-11-13, the standards listed in the table found in Attachment B to this Order are all of the reliability standards in effect in British Columbia as of the effective dates listed in Attachment B to this Order and the effective dates for the reliability standards that are listed in the table found in Attachment B supersede the effective dates that were included in any similar list appended to any previous order.

3. Individual requirements within reliability standards that incorporate, by reference, reliability standards that have not been adopted by the Commission are of no force and effect in BC.

4. Individual requirements or sub-requirements within reliability standards, which the Commission has adopted but has not determined an effective date, are of no force and effect in BC.

5. The Commission adopts the NERC Glossary of Terms Used in Reliability Standards, dated December 5, 2012, which defines terms employed in the reliability standards. The effective date of each of the new or revised glossary terms adopted in this Order is the date appearing in the table found in Attachment A to this Order. Each glossary term to be superseded by a revised glossary term adopted in this Order shall remain in effect until the effective date of the glossary term superseding it.

6. Terms within the NERC Glossary of Terms used in Reliability Standards, dated December 5, 2012 that do not include a US FERC approval date on or before November 30, 2012 are of no force or effect in BC.

7. The Commission adopts the Compliance Provisions, as defined in the Rules of Procedure for Reliability Standards in British Columbia, that accompany each of the adopted reliability standards, in the form directed by the Commisison and as amended from time to time.

8. The reliability standards adopted in BC by the Commission, will be posted on the WECC website with a link from the Commission website.

9. Attachment C to this Order contains the text of the standards adopted by this Order.

10. BC Hydro must provide a report on reliability standards, in accordance with the Act, within one year of the date the reliability standards are adopted by FERC. In assessing standards, BC Hydro should recommend appropriate BC effective dates to allow entities to come into compliance with the reliability standards within a reasonable time period.

DATED at the City of Vancouver, in the Province of British Columbia, this 12th day of December 2013.

BY ORDER

Original signed by:

D.M. Morton
Commissioner

Attachments

British Columbia Utilities Commission

Reliability Standards with Effective Dates as adopted by this Order

Standard	**Standard Name**	**Effective Date**	**Type**	**Commission Approved Standard to be Superseded**[1]
BAL-002-1	Disturbance Control Performance	Immediately after BCUC adoption	Revised	BAL-002-0
BAL-005-0.2b	Automatic Generation Control	Immediately after BCUC adoption	Revised	BAL-005-0.1b
EOP-001-0.1b	Emergency Operations Planning	R1, R3 thru R7: Immediately after BCUC adoption R2: Retired by NERC and not effective in BC	Revised	EOP-001-0
PER-001-0.2	Operating Personnel Responsibility and Authority	Immediately after BCUC adoption	Revised	PER-001-0.1
PER-003-1	Operating Personnel Credentials	1st day of the first calendar quarter 12 months after BCUC adoption	Revised	PER-003-0
PRC-004-2a	Analysis and Mitigation of Transmission and Generation Protection System Misoperations	6 months after BCUC adoption	Revised	PRC-004-1a
PRC-005-1b	Transmission and Generation Protection System Maintenance and Testing	1st day of the first calendar quarter 12 months after BCUC adoption	Revised	PRC-005-1a
PRC-023-2	Transmission Relay Loadability	R1 – R5: For circuits identified by sections 4.2.1.1 and 4.2.1.4: 1st day of the first calendar quarter, 24 months after BCUC adoption. For circuits identified by sections 4.2.1.2, 4.2.1.3, 4.2.1.5 and 4.2.1.6: 1st day of the first calendar quarter, 24 months after BCUC adoption of Requirement 6. R6: to be determined[2]	Revised	PRC-023-1
TOP-002-2.1b	Normal Operations Planning	Immediately after BCUC adoption	Revised	TOP-002-2b

[1] Commission Approved Standard to be Superseded by replacement or revised standard assessed in MRS Assessment Report No. 6.
[2] Effective date for PRC-023-2 Requirement 6 to be determined under separate process to establish “planning coordinator” function.

British Columbia Utilities Commission

NERC Glossary Terms with Effective Dates as adopted by this Order

Glossary Term[3]	Acronym	Effective Date	Commission Approved Term to be Replaced[4]
Blackstart Resource	-	Immediately after BCUC adoption	-
Interconnection Reliability Operating Limit	IROL	Immediately after BCUC adoption	Interconnection Reliability Operating Limit
Operational Planning Analysis	-	Immediately after BCUC adoption	-
Protection System		1st calendar quarter, 12 months after BCUC adoption for each entity to modify its protection system maintenance and testing program to reflect the new definition (to coincide with recommended effective date of PRC-005-1b) and until the end of the first complete maintenance and testing cycle to implement any additional maintenance and testing for battery chargers as required by that entity's program.	Protection System
Real-time Assessment		1st day of the first calendar quarter immediately after BCUC adoption	-

[3] FERC Approved Terms in the NERC Glossary of Terms as of December 5, 2012
[4] Commission Approved Terms in the NERC Glossary of Terms as of December 13, 2011

British Columbia Utilities Commission

Reliability Standards with Effective Dates adopted in British Columbia

Standard	Name	BCUC Order Adopting	Effective Date
BAL-001-0.1a	Real Power Balancing Control Performance	G-167-10	January 1, 2011
BAL-002-0 [1]	Disturbance Control Performance	G-67-09	November 1, 2010
BAL-002-1	Disturbance Control Performance	R-41-13	December 12, 2013
BAL-003-0.1b	Frequency Response and Bias	G-167-10	January 1, 2011
BAL-004-0	Time Error Correction	G-67-09	November 1, 2010
BAL-004-WECC-01	Automatic Time Error Correction	G-167-10	January 1, 2011
BAL-005-0.1b [1]	Automatic Generation Control	G-167-10	January 1, 2011
BAL-005-0.2b	Automatic Generation Control	R-41-13	December 12, 2013
BAL-006-2	Inadvertent Interchange	R-1-13	April 15, 2013
BAL-STD-002-0	Operating Reserves	G-67-09	November 1, 2010
CIP-001-2a	Sabotage Reporting	R-1-13	January 15, 2013
CIP-002-3	Cyber Security – Critical Cyber Asset Identification	G-162-11	July 1, 2012
CIP-003-3	Cyber Security – Security Management Controls	G-162-11	July 1, 2012
CIP-004-3	Cyber Security – Personnel and Training	G-162-11	July 1, 2012
CIP-005-3 [1]	Cyber Security – Electronic Security Perimeter(s)	G-162-11	July 1, 2012
CIP-005-3a	Cyber Security – Electronic Security Perimeter(s)	R-1-13	July 15, 2013
CIP-006-3c	Cyber Security – Physical Security of Critical Cyber Assets	G-162-11	July 1, 2012
CIP-007-3	Cyber Security – Systems Security Management	G-162-11	July 1, 2012
CIP-008-3	Cyber Security – Incident Reporting and Response Planning	G-162-11	July 1, 2012
CIP-009-3	Cyber Security – Recovery Plans for Critical Cyber Assets	G-162-11	July 1, 2012
COM-001-1.1	Telecommunications	G-167-10	January 1, 2011
COM-002-2	Communication and Coordination	G-67-09	November 1, 2010
EOP-001-0 [1]	Emergency Operations Planning	G-67-09	November 1, 2010
EOP-001-0.1b	Emergency Operations Planning	R-41-13	R1, R3 - R7: Dec.12, 2013 R2: Retired
EOP-002-2.1 [1]	Capacity and Energy Emergencies	G-167-10	January 1, 2011
EOP-002-3	Capacity and Energy Emergencies	R-1-13	July 15, 2013
EOP-003-1	Load Shedding Plans	G-67-09	November 1, 2010
EOP-004-1	Disturbance Reporting	G-67-09	November 1, 2010
EOP-005-1	System Restoration Plans	G-67-09	November 1, 2010

Standard	Name	BCUC Order Adopting	Effective Date
EOP-006-1	Reliability Coordination – System Restoration	G-67-09	November 1, 2010
EOP-008-0	Plans for Loss of Control Center Functionality	G-67-09	November 1, 2010
EOP-009-0	Documentation of Blackstart Generating Unit Test Results	G-67-09	November 1, 2010
FAC-001-0	Facility Connector Requirements	G-67-09	November 1, 2010
FAC-002-0 [1]	Coordination of Plans for New Generation, Transmission, and End-User	G-67-09	November 1, 2010
FAC-002-1	Coordination of Plans for New Generation, Transmission, and End-User	R-1-13	July 15, 2013
FAC-003-1	Transmission Vegetation Management Program	G-67-09	November 1, 2010
FAC-501-WECC-1	Transmission Maintenance	R-1-13	April 15, 2013
FAC-008-1	Facility Ratings Methodology	G-67-09	November 1, 2010
FAC-009-1	Establish and Communicate Facility Ratings	G-67-09	November 1, 2010
FAC-010-2.1	System Operating Limits Methodology for the Planning Horizon	G-162-11	October 30, 2011
FAC-011-2	System Operating Limits Methodology for the Operations Horizon	G-167-10	January 1, 2011
FAC-013-1	Establish and Communicate Transfer Capability	G-67-09	November 1, 2010
FAC-014-2	Establish and Communicate System Operating Limits	G-167-10	January 1, 2011
INT-001-3	Interchange Information	G-67-09	November 1, 2010
INT-003-3	Interchange Transaction Implementation	R-1-13	April 15, 2013
INT-004-2	Dynamic Interchange Transaction Modifications	G-67-09	November 1, 2010
INT-005-3	Interchange Authority Distributes Arranged Interchange	G-162-11	October 30, 2011
INT-006-3	Response to Interchange Authority	G-162-11	October 30, 2011
INT-007-1	Interchange Confirmation	G-67-09	November 1, 2010
INT-008-3	Interchange Authority Distributes Status	G-162-11	October 30, 2011
INT-009-1	Implementation of Interchange	G-67-09	November 1, 2010
INT-010-1	Interchange Coordination Exemptions	G-67-09	November 1, 2010
IRO-001-1.1	Reliability Coordination Responsibilities and Authorities	G-167-10	January 1, 2011
IRO-002-2	Reliability Coordination – Facilities	R-1-13	April 15, 2013
IRO-003-2	Reliability Coordination – Wide Area View	G-67-09	November 1, 2010
IRO-004-2	Reliability Coordination – Operations planning	R-1-13	April 15, 2013

Standard	**Name**	**BCUC Order Adopting**	**Effective Date**
IRO-005-3a	Reliability Coordination – Current Day Operations	R-1-13	April 15, 2013
IRO-006-5	Reliability Coordination – Transmission Loading Relief	R-1-13	April 15, 2013
IRO-006-WECC-1	Qualified Transfer Path Unscheduled Flow (USF) Relief	R-1-13	April 15, 2013
IRO-008-1	Reliability Coordinator Operational Analyses and Real-time Assessments	R-1-13	April 15, 2013
IRO-009-1	Reliability Coordinator Actions to Operate Within IROLs	R-1-13	April 15, 2013
IRO-010-1a	Reliability Coordinator Data Specification and Collection	R-1-13	April 15, 2013
IRO-014-1	Procedures, Processes, or Plans to Support Coordination Between Reliability coordinators	G-67-09	November 1, 2010
IRO-015-1	Notification and Information Exchange	G-67-09	November 1, 2010
IRO-016-1	Coordination of Real-Time Activities	G-67-09	November 1, 2010
MOD-001-1a	Available Transmission System Capability	G-175-11	November 30, 2011
MOD-004-1[2]	Capacity Benefit Margin	G-175-11	November 30, 2011
MOD-008-1	Transmission Reliability Margin Calculation Methodology	G-175-11	November 30, 2011
MOD-010-0	Steady-State Data for Modeling and Simulation for the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-012-0	Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-016-1.1	Documentation of Data Reporting Requirements for Actual and Forecast Demand, New Energy for Load, and Controllable Demand-Side Management	G-167-10	January 1, 2011
MOD-017-0.1	Aggregated Actual and Forecast Demands and Net Energy for Load	G-167-10	January 1, 2011
MOD-018-0	Treatment of Non member Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load	G-67-09	November 1, 2010
MOD-019-0.1	Reporting of Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators	G-167-10	January 1, 2011
MOD-020-0	Providing Interruptible Demands and Direct Control Load management Data to System Operators and Reliability Coordinators	G-67-09	November 1, 2010

Standard	Name	BCUC Order Adopting	Effective Date
MOD-021-1	Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts.	R-1-13	April 15, 2013
MOD-028-1	Area Interchange Methodology	G-175-11	November 30, 2011
MOD-029-1a	Rated System Path Methodology	G-175-11	November 30, 2011
MOD-030-02	Flowgate Methodology	G-175-11	November 30, 2011
NUC-001-2	Nuclear Plant Interface Coordination	G-167-10	January 1, 2011
PER-001-0.1 [1]	Operating Personnel Responsibility and Authority	G-162-11	October 30, 2011
PER-001-0.2	Operating Personnel Responsibility and Authority	R-41-13	December 12, 2013
PER-002-0	Operating Personnel Training	G-67-09	November 1, 2010
PER-003-0 [1]	Operating Personnel Credentials	G-67-09	November 1, 2010
PER-003-1	Operating Personnel Credentials	R-41-13	January 1, 2015
PER-004-2	Reliability Coordination – Staffing	R-1-13	January 15, 2013
PER-005-1	System Personnel Training	R-1-13	**R1, R2:** Jan. 15, 2015 **R3:** July 15, 2014 **R3.1:** Jan. 15, 2016
PRC-001-1	System Protection Coordination	G-67-09	November 1, 2010
PRC-004-1a	Analysis and Mitigation of Transmission and Generation Protection System Misoperations	R-1-13	April 15, 2013
PRC-004-2a	Analysis and Mitigation of Transmission and Generation Protection System Misoperations	R-41-13	June 12, 2014
PRC-STD-001-1 [3]	Certification of Protective Relay Applications and Settings	G-67-09	November 1, 2010
PRC-STD-003-1 [1]	Protective Relay and Remedial Action Scheme Misoperation	G-67-09	November 1, 2010
PRC-004-WECC-1	Protection System and Remedial Action Scheme Misoperation	R-1-13	July 15, 2013
PRC-005-1a [1]	Transmission and Generation Protection System Maintenance and Testing	R-1-13	April 15, 2013
PRC-005-1b	Transmission and Generation Protection System Maintenance and Testing	R-41-13	January 1, 2015
PRC-007-0	Assuring consistency of entity Underfrequency Load Shedding Program Requirements	G-67-09	November 1, 2010
PRC-008-0	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	G-67-09	November 1, 2010

Standard	**Name**	**BCUC Order Adopting**	**Effective Date**
PRC-009-0	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	G-67-09	November 1, 2010
PRC-010-0	Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	G-67-09	November 1, 2010
PRC-011-0	Undervoltage Load Shedding system Maintenance and Testing	G-67-09	November 1, 2010
PRC-015-0	Special Protection System Data and Documentation	G-67-09	November 1, 2010
PRC-016-0.1	Special Protection System Misoperations	G-167-10	January 1, 2011
PRC-017-0	Special Protection System Maintenance and Testing	G-67-09	November 1, 2010
PRC-018-1	Disturbance Monitoring Equipment Installation and Data Reporting	G-67-09	November 1, 2010
PRC-021-1	Under Voltage Load Shedding Program Data	G-67-09	November 1, 2010
PRC-022-1	Under Voltage Load Shedding Program Performance	G-67-09	November 1, 2010
PRC-023-1 [1]	Transmission Relay Loadability	G-162-11	**R1, R2:** Applicability Criteria 5.1.1: Jan. 1, 2012 Applicability Criteria 5.1.2: Apr. 1, 2015 Applicability Criteria 5.1.3: Apr. 21, 2015 **R3:** To be determined [4]
PRC-023-2	Transmission Relay Loadability	R-41-13	**R1-R5:** For circuits identified by Sections 4.2.1.1 and 4.2.1.4: January 1, 2016 __________________ For circuits identified by Sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6: To be determined [4] **R6**: To be determined [4]
TOP-001-1a	Reliability Responsibilities and Authorities	R-1-13	January 15, 2013
TOP-002-2b [1]	Normal Operations Planning	R-1-13	January 15, 2013
TOP-002-2.1b	Normal Operations Planning	R-41-13	December 12, 2013
TOP-003-1	Planned Outage Coordination	R-1-13	April 15, 2013

Standard	Name	BCUC Order Adopting	Effective Date
TOP-004-2	Transmission Operations	G-167-10	January 1, 2011
TOP-005-2a	Operational Reliability Information	R-1-13	April 15, 2013
TOP-006-2	Monitoring System Conditions	R-1-13	April 15, 2013
TOP-007-0	Reporting System Operating Unit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	G-67-09	November 1, 2010
TOP-007-WECC-1	System Operating Limits	R-1-13	April 15, 2013
TOP-008-1	Response to Transmission Unit Violations	G-67-09	November 1, 2010
TPL-001-0.1	System Performance Under Normal (No Contingency) Conditions (Category A)	G-167-10	January 1, 2011
TPL-002-0b	System Performance Following Loss of a Single Bulk Electric System Element (Category B)	R-1-13	January 15, 2013
TPL-003-0a	System Performance Following Loss of a Single Bulk Electric System Element (Category C)	G-162-11	October 30, 2011
TPL-004-0	System Performance Following Loss of a Single Bulk Electric System Element (Category D)	G-67-09	November 1, 2010
VAR-001-1 [1]	Voltage and Reactive Control	G-67-09	November 1, 2010
VAR-001-2	Voltage and Reactive Control	R-1-13	July 15, 2013
VAR-002-1.1b	Generator Operation for Maintaining Network Voltage Schedules	G-162-11	October 30, 2011
VAR-STD-002a-1 [1]	Automatic Voltage Regulators (AVR)	G-67-09	November 1, 2010
VAR-002-WECC-1	Automatic Voltage Regulators (AVR)	R-1-13	January 15, 2014
VAR-STD-002b-1 [1]	Power System Stabilizer (PSS)	G-67-09	November 1, 2010
VAR-501-WECC-1	Power System Stabilizer (PSS)	R-11-13	January 15, 2014

[1] Standard is superseded by the revised/replacement standard listed immediately below it as of the effective date(s) of the revised/replacement standard.

[2] MOD-006-0.1 and MOD-007-0 were superseded by the MOD-004-1 standard as of the MOD-004-1 effective date and were removed from list.

[3] Standard is superseded by the PRC-004-WECC-1 standard as of the PRC-004-WECC-1 effective date.

[4] Standard effective date is to be determined under a process to establish Planning Coordinator functional registration.

A. Introduction

1. **Title:** **Disturbance Control Performance**
2. **Number:** BAL-002-1
3. **Purpose:** The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.
4. **Applicability:**
   - **4.1.** Balancing Authorities
   - **4.2.** Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)
   - **4.3.** Regional Reliability Organizations
5. **(Proposed) Effective Date*:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group.

R2.2. Its allocation among members.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently

***Mandatory BC Effective Date: December 12, 2013**

than annually, their probable contingencies to determine their prospective most severe single contingencies.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

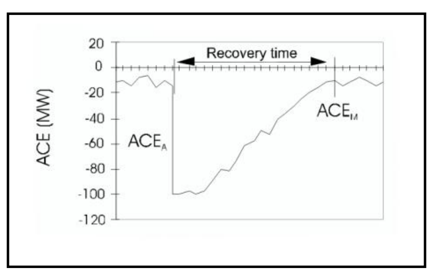
R6.2. The default Contingency Reserve Restoration Period is 90 minutes.

C. Measures

M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).

For loss of generation:

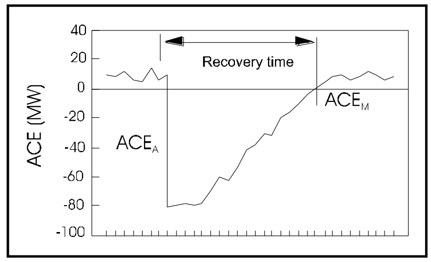
if $ACE_A < 0$
then



$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$

if $ACE_A \geq 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

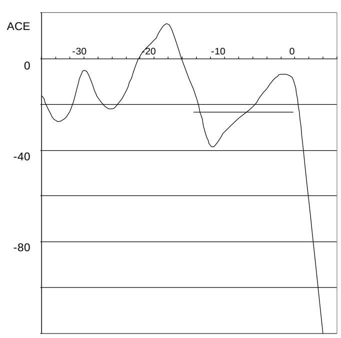


where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15\ min}$, and

The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = **-** 25 MW.



The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Entity must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

1.5. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCS in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

3. Violation Severity Levels (no changes)

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
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 321.	Revised.

A. Introduction

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

2. **Number:** BAL-005-0.2b

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

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Generator Operators

   4.3. Transmission Operators

   4.4. Load Serving Entities

5. **Effective Date*:** May 13, 2009

B. Requirements

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

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

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

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

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard. (Retirement approved by NERC BOT pending applicable regulatory approval.)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Authority

Balancing Authorities shall be prepared to supply data to The British Columbia Utilities Commission (BCUC) in the format defined below:

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

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

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

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

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

Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 — Interpretation of Requirement R17 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to "0.1b"	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from "BAL-005-1" to "BAL-005-0)	Errata
0.2b	September 13, 2012	FERC approved – Updated Effective Date	Addition
0.2b	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	

Appendix 1

Effective Date: August 27, 2008 (U.S.)

Interpretation of BAL-005-0 Automatic Generation Control, R17

Request for Clarification received from PGE on July 31, 2007

PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:

- *Only equipment within the operations control room*
- *Only equipment that provides values used to calculate AGC ACE*
- *Only equipment that provides values to its SCADA system*
- *Only equipment owned or operated by the BA*
- *Only to new or replacement equipment*
- *To all equipment that a BA owns or operates*

BAL-005-0

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

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

Existing Interpretation Approved by Board of Trustees May 2, 2007

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

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

Interpretation provided by NERC Frequency Task Force on September 7, 2007 and Revised on November 16, 2007

As noted in the existing interpretation, BAL-005-0 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17.

The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

A. Introduction

1. **Title:** **Emergency Operations Planning**

2. **Number:** EOP-001-0.1b

3. **Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Transmission Operators.

5. **Effective Date*:** April 1, 2005

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

R3. Each Transmission Operator and Balancing Authority shall:

R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R3.3. Develop, maintain, and implement a set of plans for load shedding.

R3.4. Develop, maintain, and implement a set of plans for system restoration.

R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R4.1. Communications protocols to be used during emergencies.

R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R4.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R4.4. Staffing levels for the emergency.

***Mandatory BC Effective Date: R1, R3 – R7: December 12, 2013, R2: Retired**

R5. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.

R6. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R7. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R7.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R7.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R7.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R7.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Timeframes

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

Additional Compliance Information

Not specified.

2. **Levels of Non-Compliance**

2.1. Level 1: One of the applicable elements of Attachment 1-EOP-001 has not been addressed in the emergency plans.

2.2. Level 2: Two of the applicable elements of Attachment 1-EOP-001 have not been addressed in the emergency plans.

2.3. Level 3: Three of the applicable elements of Attachment 1-EOP-001 have not been addressed in the emergency plans.

2.4. Level 4: Four or more of the applicable elements of Attachment 1-EOP-001 have not been addressed in the emergency plans or a plan does not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0b	November 4, 2010	Adopted by the Board of Trustees	Project 2008-09 - Interpretation of Requirement R1
0b	November 4, 2010	Adopted by the Board of Trustees	Project 2009-28 - Interpretation of Requirement R2.2 (R3.2 in EOP-001-0)
0b	December 15, 2011	FERC Order issued approving Interpretation of R1 and R3.2 (Order effective December 15, 2011)	Project 2008-09 - Interpretation of Requirement R1 and Project 2009-28 - Interpretation of Requirement R2.2 (R3.2 in EOP-001-0)
0.1b	March 8, 2012	Errata adopted by Standards Committee; (changed title and references to Attachment 1 to omit inclusion of version numbers and corrected reference in Appendix 2 from “R2.2” to “R3.2”)	Errata
0.1b	September 13, 2012	FERC approved	Errata

Attachment 1-EOP-001

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-0, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-0.

Appendix 2

Requirement Number and Text of Requirement
R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001."

A. Introduction

1. **Title:** **Operating Personnel Responsibility and Authority**

2. **Number:** PER-001-0.2

3. **Purpose:** Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date*:** December 10, 2009

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The job description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit or Interconnection Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

Compliance Monitoring Authority: The British Columbia Utilities Commission

1. **Compliance Monitoring Process**

Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

***Mandatory BC Effective Date: December 12, 2013**

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0.1	April 15, 2009	Replaced "position" with "job" on M1.1	Errata
0.1	April 15, 2009	Errata adopted by Standards Committee	Errata
0.1	December 10, 2009	Approved by FERC — added effective date	Update

0.2	March 8, 2012	Errata adopted by Standards Committee; (moved the word, “Interconnection” in Measure M1.4. so that it appears as the first word in the term “Interconnection Reliability Operating Limit” rather than the last word in the phrase, “System Operating Limit Interconnection)	Errata
0.2	September 13, 2012	FERC approved	Errata

A. Introduction

1. **Title:** **Operating Personnel Credentials**

2. **Number:** **PER-003-1**

3. **Purpose:** To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System.

4. **Applicability:**

   4.1. Reliability Coordinator

   4.2. Transmission Operator

   4.3. Balancing Authority

5. **Effective Date*:**

   5.1. In those jurisdictions where regulatory approval is required, this standard shall become effective the first calendar day of the first calendar quarter twelve months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective the first calendar day of the first calendar quarter twelve months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate [(1)]: *[Risk Factor: High][Time Horizon: Real-time Operations]*

1.1. Areas of Competency

1.1.1. Resource and demand balancing

1.1.2. Transmission operations

1.1.3. Emergency preparedness and operations

1.1.4. System operations

1.1.5. Protection and control

1.1.6. Voltage and reactive

1.1.7. Interchange scheduling and coordination

1.1.8. Interconnection reliability operations and coordination

[1] Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)] : *[Risk Factor: High][Time Horizon: Real-time Operations]*:

2.1. Areas of Competency

2.1.1. Transmission operations

2.1.2. Emergency preparedness and operations

2.1.3. System operations

2.1.4. Protection and control

2.1.5. Voltage and reactive

2.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Transmission Operator

R3. Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates [(1)] : *[Risk Factor: High][Time Horizon: Real-time Operations]*:

3.1. Areas of Competency

3.1.1. Resources and demand balancing

3.1.2. Emergency preparedness and operations

3.1.3. System operations

3.1.4. Interchange scheduling and coordination

3.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Balancing and Interchange Operator

C. Measures

M1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have the following evidence to show that it staffed its Real-time operating positions

[1] Non-NERC certified personnel performing any reliability-related task of an operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate (R1, R2, R3):

M1.1 A list of Real-time operating positions.

M1.2 A list of System Operators assigned to its Real-time operating positions.

M1.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M1.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is the greatest, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent records.

1.4. Additional Compliance Information

None.

2.0 Violation Severity Levels

R#	Lower VSL	Medium VSL	High VSL	Severe VSL
R1				The Reliability Coordinator failed to staff each Real-time operating position performing Reliability Coordinator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R1.
R2				The Transmission Operator failed to staff each Real-time operating position performing Transmission Operator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R2, Part 2.2.
R3				The Balancing Authority failed to staff each Real-time operating position performing Balancing Authority reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R3, Part 3.2.

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Complete revision under Project 2007-04	Revision
1	February 17, 2011	Adopted by Board of Trustees	
1	September 15, 2011	FERC Order issued by FERC approving PER-003-1 (effective date of the Order is September 15, 2011)	

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations

2. **Number:** PRC-004-2a

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **(Proposed) Effective Date*:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   The British Columbia Utilities Commission.

***Mandatory BC Effective Date: June 12, 2014**

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	
2	August 5, 2010	Adopted by the NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the NERC Board of Trustees	

1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	

Appendix 1

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

A. Introduction

1. **Title:** **Transmission and Generation Protection System Maintenance and Testing**

2. **Number:** PRC-005-1b

3. **Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Generator Owner.

   4.3. Distribution Provider that owns a transmission Protection System.

5. **Effective Date*:** To be determined

B. Requirements

R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:

R1.1. Maintenance and testing intervals and their basis.

R1.2. Summary of maintenance and testing procedures.

R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:

R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.

R2.2. Date each Protection System device was last tested/maintained.

C. Measures

M1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.

M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Authority

   The British Columbia Utilities Commission

***Mandatory BC Effective Date: January 1, 2015**

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

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

1.4. Additional Compliance Information

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program provided was incomplete as required in R1, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: Documentation of the maintenance and testing program provided was complete as required in R1, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: Documentation of the maintenance and testing program provided was incomplete, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/05

1	February 7, 2006	Adopted by NERC Board of Trustees	
1a	November 5, 2009	Interpretation of R1, R1.1, and R1.2 adopted by the NERC Board of Trustees	Project 2009-10 Interpretation
1a	February 17, 2011	Interpretation regarding applicability of standard to protection of radially connected transformers adopted by the NERC Board of Trustees (adopted and filed as -1a instead of -1b)	Project 2009-17 Interpretation
1a	September 26, 2011	FERC Order issued approving interpretation regarding applicability of standard to protection of radially connected transformers (FERC's Order is effective as of September 26, 2011)	Project 2009-17 Interpretation
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order is effective as of March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation

Appendix 1

Requirement Number and Text of Requirement
R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include: **R1.1.** Maintenance and testing intervals and their basis. **R1.2.** Summary of maintenance and testing procedures. **R2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include: **R2.1** Evidence Protection System devices were maintained and tested within the defined intervals. **R2.2** Date each Protection System device was last tested/maintained.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-005-1 Requirements R1 and R2 focuses on the applicability of the term “transmission Protection System.” The NERC Glossary of Terms Used in Reliability Standards contains a definition of “Protection System” but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

Appendix 2[1]

Requirement Number and Text of Requirement
R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include: **R1.1.** Maintenance and testing intervals and their basis. **R1.2.** Summary of maintenance and testing procedures.
Question #1
Does R1 require a maintenance and testing program for the battery chargers for the "station batteries" that are considered part of the Protection System?
Response to Question #1
While battery chargers are vital for ensuring "station batteries" are available to support Protection System functions, they are not identified within the definition of "Protection Systems." Therefore, PRC-005-1 does not require maintenance and testing of battery chargers.
Question #2
Does R1 require a maintenance and testing program for auxiliary relays and sensing devices? If so, what types of auxiliary relays and sensing devices? (i.e. transformer sudden pressure relays)
Response to Question #2
The existing definition of "Protection System" does not include auxiliary relays; therefore, maintenance and testing of such devices is not explicitly required. Maintenance and testing of such devices is addressed to the degree that an entity's maintenance and testing program for DC control circuits involves maintenance and testing of imbedded auxiliary relays. Maintenance and testing of devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included within Requirement R1.
Question #3
Does R1 require maintenance and testing of transmission line re-closing relays?
Response to Question #3
No. "Protective Relays" refer to devices that detect and take action for abnormal conditions. Automatic restoration of transmission lines is not a "protective" function.
Question #4
Does R1 require a maintenance and testing program for the DC circuitry that is just the circuitry with relays and devices that control actions on breakers, etc., or does R1 require a program for the entire circuit from the battery charger to the relays to circuit breakers and all associated

[1] According to the FERC Order issued approving a modified definition of Protection System (RD11-13-000), this interpretation will be superseded by the modified definition of Protection System when the modified definition becomes effective. The modified definition of Protection System becomes effective on April 1, 2013.

wiring?
Response to Question #4
PRC-005-1 requires that entities 1) address DC control circuitry within their program, 2) have a basis for the way they address this item, and 3) execute the program. PRC-005-1 does not establish specific additional requirements relative to the scope and/or methods included within the program.
Question #5
For R1, what are examples of "associated communications systems" that are part of “Protection Systems” that require a maintenance and testing program?
Response to Question #5
“Associated communication systems” refer to communication systems used to convey essential Protection System tripping logic, sometimes referred to as pilot relaying or teleprotection. Examples include the following: • communications equipment involved in power-line-carrier relaying • communications equipment involved in various types of permissive protection system applications • direct transfer-trip systems • digital communication systems (which would include the protection system communications • functions of standard IEC 618501 as well as various proprietary systems)

A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-2

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability**

   4.1. Functional Entity

   4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).*

   4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).*

   4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1*(Circuits Subject to Requirements R1 – R5),* provided those circuits have bi-directional flow capabilities.

   4.1.4 Planning Coordinators

   4.2. Circuits

   4.2.1 Circuits Subject to Requirements R1 – R5

   4.2.1.1 Transmission lines operated at 200 kV and above.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

   4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

   4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

   4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

   4.2.2 Circuits Subject to Requirement R6

   4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

   4.2.2.2 Transmission lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

5. **Effective Dates***

The effective dates of the requirements in the PRC-023-2 standard corresponding to the applicable Functional Entities and circuits are summarized in the following table:

* **Mandatory BC Effective Date: Requirement Dependent**

Standard PRC-023-2 — Transmission Relay Loadability

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First calendar quarter after Board of Trustees adoption
	• For Requirement R1, criterion 10.1, to set transformer fault protection relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability	First day of the first calendar quarter 12 months after applicable regulatory approvals	First day of the first calendar quarter 12 months after Board of Trustees adoption
	• For supervisory elements as described in PRC-023-2 - Attachment A, Section 1.6	First day of the first calendar quarter 24 months after applicable regulatory approvals	First day of the first calendar quarter 24 months after Board of Trustees adoption
	• For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3	Later of the first day of the first calendar quarter after applicable regulatory approvals of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013)	Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011[1]
	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on

1 July 1, 2011 is the first day of the first calendar quarter 39 months following the Board of Trustees February 12, 2008 approval of PRC-023-1.

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
		list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption
	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption
R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption
R6	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5	First day of the first calendar quarter 18 months after applicable regulatory approvals	First day of the first calendar quarter 18 months after Board of Trustees adoption

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
   - 115% of the highest emergency rating of the series capacitor.
   - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating

10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[3].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[4].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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[3] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4

[4] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-2 per application of Attachment B, including identification of the first calendar year in which any criterion in Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Authority

The British Columbia Utilities Commission

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

If a Transmission Owner, Generator Owner, Distribution Provider or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Monitor shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit. OR

Requirement	Lower	Moderate	High	Severe
				The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments.	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments.	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established within

Requirement	Lower	Moderate	High	Severe
		OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission

Requirement	Lower	Moderate	High	Severe
				Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

   "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

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Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	

PRC-023 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Generator protection relays that are susceptible to load.

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[5] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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[5] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

A. Introduction

1. **Title:** **Normal Operations Planning**
2. **Number:** TOP-002-2.1b
3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.
4. **Applicability**
   - **4.1.** Balancing Authority.
   - **4.2.** Transmission Operator.
   - **4.3.** Generator Operator.
   - **4.4.** Load Serving Entity.
   - **4.5.** Transmission Service Provider.
5. **Effective Date*:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

***Mandatory BC Effective Date: December 12, 2013**

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real output capabilities.

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real capabilities. (Requirement 14)

M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Balancing Authorities:

2.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not maintain an updated set of current-day plans as specified in R1.

2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. Levels of Non-Compliance for Transmission Operators

3.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

3.2. Level 2: Not applicable.

3.3. Level 3: One or more of Bulk Electric System studies were not made available as specified in R11.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Did not maintain an updated set of current-day plans as specified in R1.

3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.

3.4.3 Studies not updated to reflect current system conditions as specified in R11.

3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. Levels of Non-Compliance for Generator Operators:

4.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:

5.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable.

5.4. Level 4: Not applicable.

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 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata

Appendix 1

Interpretation of Requirement R11

Requirement Number and Text of Requirement

Requirement R11: The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Question #1
Is the Transmission Operator required to conduct a "unique" study for each operating day, even when the actual or expected system conditions are identical to other days already studied? In other words, can a study be used for more than one day?

Response to Question #1
Requirement R11 mandates that each Transmission Operator review (i.e., study) the state of its Transmission Operator area both in advance of each day and during each day. Each day must have "a" study that can be applied to it, but it is not necessary to generate a "unique" study for each day. Therefore, it is acceptable for a Transmission Operator to use a particular study for more than one day.

Question #2
Are there specific actions required to implement a "study"? In other words, what constitutes a study?

Response to Question #2
The requirement does not mandate a particular type of review or study. The review or study may be based on complex computer studies or a manual reasonability review of previously existing study results. The requirement is designed to ensure the Transmission Operator maintains sensitivity to what is happening or what is about to happen.

Question #3
Does the term, "to determine SOLs" as used in the first sentence of Requirement R11 mean the "determination of system operating limits" or does it mean the "identification of potential SOL violations?"

Response to Question #3
TOP-002-2 covers real-time and near-real-time studies. Requirement R11 is meant to include both determining new limits and identifying potential "exceedances" of pre-defined SOLs. If system conditions indicate to the Transmission Operator that prior studies and SOLs may be outdated, TOP-002-2 mandates the Transmission Operator to conduct a study to identify SOLs for the new conditions. If the Transmission Operator determines that system conditions do not warrant a new study, the primary purpose of the review is to check that the previously defined (i.e., defined from the current SOLs in use, or the set defined by the planners) SOLs are not expected to be exceeded. As written, the standard provides the Transmission Operator discretion regarding when to look for new SOLs and when to rely on its current set of SOLs.

Standard TOP-002-2.1b — Normal Operations Planning

Appendix 2

Requirement Number and Text of Requirement:

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

Clarification needed:

Requirement 10 is proposed to be eliminated in Project 2007-03 because it is redundant with TOP-004-0 R1, which only applies to TOP not to BA. However, that will not be effective for more than two years. In the meantime, in Requirement 10 is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?

Project 2009-27: Response to Request for an Interpretation of TOP-002-2a, Requirement R10, for Florida Municipal Power Pool

The following interpretation of TOP-002-2a — Normal Operations Planning, Requirement R10, was developed by the Real-time Operations Standard Drafting Team.

Requirement Number and Text of Requirement

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

Question

In Requirement 10, is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?

Response

Yes. As stated in the NERC *Glossary of Terms used in Reliability Standards*, the Balancing Authority is responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance within a Balancing Authority Area, and supporting Interconnection frequency in real time. The Balancing Authority does not possess the Bulk Electric System information necessary to manage transmission flows (MW, MVAR or Ampere) or voltage. Therefore, the Balancing Authority must follow the directions of the Transmission Operator to meet all SOLs and IROLs.

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
MANDATORY RELIABILITY STANDARDS
ASSESSMENT REPORT NO. 6 AND
THE DETERMINATION OF RELIABILITY STANDARDS
FOR ADOPTION IN BRITISH COLUMBIA

REASONS FOR DECISION

January 16, 2014

BEFORE:

L.F. Kelsey, Commissioner
N.E. MacMurchy, Commissioner
D.M. Morton, Commissioner
R.D. Revel, Commissioner

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EXECUTIVE SUMMARY

On May 24, 2013, BC Hydro filed Mandatory Reliability Standards Assessment Report No. 6 pursuant to section 125.2(3) of the *Utilities Commission Act.* BC Hydro filed MRS Assessment Report No. 6 to meet its requirements under subsection 3(1) of the Mandatory Reliability Standards Regulation, BC Reg 32/2009, M039 (MRS Regulation) which requires it to file a report assessing a reliability standards) within one year of the date when the standard is adopted by the Federal Energy Regulatory Commission (FERC). MRS Assessment Report No. 6 covers those standards approved by FERC and which became enforceable in the United States (U.S.) during the period of December 1, 2011 to November 30, 2012.

The British Columbia Utilities Commission (Commission) issued Order R-41-13. In a letter dated December 20, 2013, BC Hydro requests the Commission provide Reasons for Decision supporting Order R-41-13, among other things. BC Hydro also requested clarification of Directive 10 of the Order and the treatment of the Western Electricity Coordinating Council (WECC) Regional Criteria. These Reasons for Decision provide further clarification of specific determinations made. In particular the Reasons address:

- BC Hydro's recommendations regarding the reliability standards, North American Electric Reliability Corporation (NERC) Glossary Terms and certain corrections to reliability standards adopted in BC;
- BC Hydro's interpretation of "adopted" in section 3(1) of the MRS Regulation as it relates to BC Hydro's approach for assessing mandatory reliability standards (standards);
- BC Hydro's proposed refined approach for assessing individual requirements of standards;
- BC Hydro's recommendation that the Commission issue an Order directing BC registered entities to comply with Western Electricity Coordinating Council (WECC) Criteria in order to demonstrate compliance with PRC-004-2a; and
- BC Hydro's recommendation regarding reliability standards that place reliability related obligations on a Planning Coordinator (PC); In the following sections the Commission provides discussion and determinations on each issue listed above.

With respect to the matter noted above the Commission makes the following determinations:

- The Commission adopts the nine revised standards (Revised Standards) assessed in MRS Assessment Report No. 6 and related materials as the Commission considers that the Revised Standards are required to maintain or achieve consistency in BC with other jurisdictions that have adopted the reliability standards.
- The Commission adopts the NERC Glossary of Terms dated December 5, 2012 as it will maintain or achieve consistency with NERC standards going forward.
- In order to provide clarification for currently adopted Reliability Standards, the Commission directs the adoption of the effective dates included in Appendix D – Draft Order; Attachment B of the Report, as amended by the Errata.
- BC Hydro must provide a report on reliability standards, in accordance with the Act, within one year of the date the reliability standards are adopted by FERC. In assessing standards, BC Hydro should

recommend appropriate BC effective dates to allow entities to come into compliance with the reliability standards within a reasonable period of time;

- The Commission is not persuaded by BC Hydro's proposed refined approach for assessing individual requirements of standards;

- The Commission confirms that BC entities should comply with the WECC Criterion PRC-003-WECC-CRT-1.2 for the purposes of demonstrating compliance with Standard PRC-004-2a;

- The Commission effectively accepts BC Hydro's request to rescind the effective date for Requirement 3 of PRC-023-1 (removing the Effective Date as noted in Appendix B of Order R-41-13) and BC Hydro's recommendation regarding PRC-023-2.

1.0 INTRODUCTION

On May 24, 2013, BC Hydro filed Mandatory Reliability Standards (MRS) Assessment Report No. 6 pursuant to section 125.2(3) of the *Utilities Commission Act* (Act). The British Columbia Utilities Commission (Commission) issued Order R-41-13, on December 12, 2013, adopting nine revised reliability standards (Revised Standards), among other things. In a letter dated December 20, 2013, BC Hydro requested the Commission provide Reasons for Decision supporting Order R-41-13, among other things. BC Hydro also requested clarification of Directive 10 of the Order and the treatment of Western Electricity Coordinating Council (WECC) Regional Criteria.

These Reasons for Decision support and clarify determinations made with regard to MRS Assessment Report No. 6 in Commission Order R-41-13, particularly Directive 10. They also respond to issues raised by BC Hydro in MRS Assessment Report No. 6 and in the BC Hydro December 20, 2013 letter. Those issues are:

- BC Hydro's interpretation of the term "adopted" in subsection 3(1) of the Mandatory Reliability Standards Regulation BC Reg. 32/2009, Ministerial Order M039/2009 (MRS Regulation) as it relates to BC Hydro's MRS assessment approach;

- BC Hydro's proposed refined approach of assessing requirements of reliability standards;

- BC Hydro's recommendation that the Commission issue an Order directing BC registered entities to comply with WECC Criteria in order to demonstrate compliance with PRC-004-2a; and

- BC Hydro's recommendation that only those requirements of reliability standard PRC-023-2 that do not rely on actions to be taken by the Planning Coordinator (PC) be adopted in BC at this time and request that the Commission issue an Order rescinding the effective date of Requirement 3 of PRC-023-1 (previously ordered by Commission Order G-162-11).

2.0 BACKGROUND AND REGULATORY PROCESS

MRS Assessment Report No. 6 assesses standards adopted by the Federal Energy Regulatory Commission (FERC) which became enforceable in the United States (U.S.) between December 1, 2011 and November 30, 2012 (2012 Assessment Period). Section 125.2(3) of the Act requires BC Hydro to review each reliability standard and provide to the Commission, in accordance with the regulations, a report assessing:

a) Any adverse impact of the reliability standard on the reliability of electricity transmission in British Columbia (BC) if the reliability standard were adopted;

b) The suitability of the reliability standard for BC;

c) The potential cost of the reliability standard if it were adopted; and

d) Any other matter prescribed by regulation or identified by order of the Commission for the purposes of section 125.2 of the Act.

Section 3(1) of the MRS Regulation states that:

> "subject to subsection (2), a report on a reliability standard, prepared by the transmission corporation [now the authority] in accordance with section 125.2(3) of the Act, must be

> provided to the commission within one year of (a) the date the reliability standard is adopted by the regulatory body with jurisdiction over the standard making body that established the reliability standard…"

For efficiency, rather than submitting a separate assessment report for each reliability standard that is adopted in the U.S. by FERC, BC Hydro batches standards, assesses them and files one assessment report with the Commission each year. BC Hydro's annual assessment period has been December 1 to November 30. BC Hydro committed that:

> "should BC Hydro or the BCUC determine that a particular reliability standard is sufficiently critical to reliability that it warrants immediate implementation, BC Hydro will file a standard-specific assessment report and not wait until its next 'batch' assessment report, as was the case for the standards assessed in MRS Assessment Report No. 4..." (Exhibit B-1, MRS Assessment Report No. 6, Section 8 – Future Assessment Reports, p. 30 lines 26 to p. 31 line 1).

In MRS Assessment Report No. 6, BC Hydro identified Revised Standard PRC-004-2a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations as a standard to be assessed under MRS Assessment Report No. 6. However, Requirements 1, 2 and 3 of Revised Standard PRC-004-2a reference "Regional Entity's Procedures." BC Hydro indicated that at the time of assessment it was unclear of what the Regional Entity's Procedures would be and thus was not able to recommend that this Revised Standard be adopted in BC. Further, BC Hydro requested that the Commission clarify what constitutes the Regional Entity's Procedures (Exhibit B-1, MRS Assessment Report No. 6, Section 2.3 – PRC-004-2a, p. 6, lines 2-18).

By letter dated July 3, 2013, the Commission issued a letter to BC Hydro and attached WECC's Regional Criterion PRC-003-WECC-CRT-1.2 with errata dated June 26, 2013 and the corresponding reporting template (together, the WECC Criterion) and indicated together those documents describe the procedures for reporting under PRC-004-2a. The Commission requested BC Hydro complete its assessment of PRC-004-2a and provide its recommendations as soon as possible as an addendum to MRS Assessment Report No. 6.

Further, on July 25, 2013, the Commission issued Order R-30-13 directing BC Hydro to file the addendum by September 30, 2013 and attaching a Regulatory Timetable establishing a comment process for review of MRS Assessment Report No. 6.

BC Hydro filed the Addendum to MRS Assessment Report No. 6 on September 30, 2013, as directed in Order R-30-13. BC Hydro also filed two Errata to the Addendum (No. 1 and No. 2) on October 18 and November 27, 2013 respectively. Errata No. 1 corrected a transposition error and Errata No. 2 requested that the Commission adopt only specific requirements of a standard (EOP-001-0.1b) to reflect the retirement of requirement 2 of the standard in the U.S. BC Hydro also provided a revised Attachment A and Attachment B of Appendix D of MRS Assessment Report No. 6.

In accordance with the Regulatory Timetable established by Order R-30-13, FortisBC Inc. submitted comments on MRS Assessment Report No. 6 on October 15, 2013. FortisBC Inc. indicated that its input was reflected in MRS Assessment Report No. 6 and that it had no additional comments on the report. No other stakeholders submitted comments. The Commission issued Information Request (IR) No. 1 on November 12, 2013 to which BC Hydro responded on November 27, 2013.

The Commission reviewed MRS Assessment Report No. 6 and related documents, and issued Order R-41-13 on December 12, 2013. Subsequently BC Hydro requested that the Commission provide Reasons for Decision in support of the Order. BC Hydro requested clarification of Directive 10 of Order R-41-13 and reasons why the Commission did not include a directive ordering entities to comply with PRC-003-WECC-CRT-1.2 for the purposes of demonstrating compliance with Revised Standard PRC-004-2a.

3.0 RELIABILITY STANDARDS AND DECEMBER 5, 2012 NERC GLOSSARY

This section addresses:

1. The recommendation to adopt the nine Revised Standards assessed in MRS Assessment Report No. 6 and Addendum (Directive 1 of Order R-41-13);

2. The recommendation to adopt the December 5, 2012 NERC Glossary of Terms (Directive 5 of Order R-41-13); and

3. The recommendation that the Commission make certain corrections and clarifications to currently adopted reliability standards (Directive 2 of Order R-41-13).

3.1 Recommendation to Adopt Revised Standards

In total BC Hydro assessed nine Revised Standards, eight in the MRS Assessment Report No. 6 and one in the Addendum, which became enforceable in the U.S. during the 2012 Assessment Period and concluded the assessed Revised Standards will preserve or enhance the reliability of the bulk electric system in BC, and thus will serve the public interest and are suitable for adoption in BC based on the criteria applied in the assessment of these standards. As such, BC Hydro recommended that the Revised Standards be adopted by the Commission (Exhibit B-1, MRS Assessment Report No. 6, Section 10 – Conclusions, p. 32, lines 23-29).

3.2 Recommendation to Adopt December 5, 2012 NERC Glossary

BC Hydro indicated that the Revised Standards assessed in MRS Assessment Report No. 6 were assessed based on the defined terms contained in the NERC Glossary Used in Reliability Standards (NERC Glossary) dated December 5, 2012. As a result, the NERC Glossary dated December 13, 2011, which was previously adopted by Commission Order R-1-13 would be out of date (Exhibit B-1, MRS Assessment Report No. 6, Section 6 – NERC Glossary of Terms, pp. 22-23).

As part of MRS Assessment Report No. 6, BC Hydro also states in Section 2.1 – Assessment Process for Requirements:

> "With respect to the NERC Glossary, BC Hydro considers it appropriate that the BCUC adopt the most current Glossary adopted by NERC during the annual assessment period. BC Hydro proposes that it will assess those defined terms in the Glossary that were FERC approved during the Assessment Period, whether or not they became effective, and will make recommendations for effective dates of new or revised defined terms where appropriate. This is consistent with BCUC Order No. R-1-13 dated January 15, 2013 which directed in Directive 10 that 'definitions within the NERC Glossary used in Reliability Standards, dated December 13, 2011, which have not been approved by the U.S. Federal Energy Reliability Commission, are of no force or effect'. This will allow versions of the NERC Glossary to be adopted in their entirety in advance of any new or revised defined terms contained in them being required in B.C., and avoids maintaining a 'B.C. only' glossary of terms. BC Hydro may

revisit the need for a 'B.C. only' glossary of terms in a future MRS assessment report(s) if it becomes apparent that the NERC Glossary is diverging from the standards that have been adopted by the BCUC" (Exhibit B-1, MRS Assessment Report No. 6 Section 2.1 Assessment Process for Requirements, p. 3, lines 10-23).

Regarding the NERC Glossary BC Hydro recommends the following:

- As the updated December 5, 2012 version of the NERC Glossary is integral to the reliability standards, it should be adopted by the Commission in conjunction with the Revised Standards assessed in MRS Assessment Report No. 6 to achieve and maintain consistency with NERC standards going forward. Any definitions in the NERC Glossary that are not approved by FERC on or before November 30, 2012 should not become effective in BC.

- Definitions within the NERC Glossary, dated December 5, 2012, that are not identified in this version of the Glossary as having a FERC approval date on or before November 30, 2012, should be of no force or effect in B.C.

- Any definitions that are identified as being remanded or retired in the NERC Glossary should be ordered by the Commission to be of no force or effect in BC once the terms that replace them become effective in BC.

(Exhibit B-1, MRS Assessment Report No. 6, Section 6.2 – Summary of Final Assessment of Glossary Terms, p. 28, lines 4-22)

3.3 Corrections and Clarifications to Adopted Reliability Standards

BC Hydro also indicated that through the assessment process, BC Hydro and FortisBC Inc. identified several inconsistencies or corrections required to currently adopted reliability standards. In light of those identified inconsistencies, BC Hydro conducted a thorough review of all previously adopted standards to ensure the effective dates for all standards adopted in BC were accurately reflected in the MRS Assessment Report No. 6 documentation (Appendix D, Attachment B to the Report).

To correct the inconsistencies, BC Hydro recommended that the Commission order standards MOD-006-0.1 and MOD-007.0 no longer effective and superseded by MOD-004-1, effective November 30, 2011. BC Hydro also recommended additional inconsistencies be clarified by way of the Commission adopting the effective dates included in Appendix D – Draft Order; Attachment B of MRS Assessment Report No. 6 (Exhibit B-1, MRS Assessment Report No. 6, Section 9 – Inconsistencies in Adopted Standards, pp. 31-32).

On November 27, 2013, BC Hydro further revised Attachment A and Attachment B to Appendix D of the Report in Errata No. 2 to the MRS Assessment Report No. 6. (Exhibit B-2-2, Errata No. 2 to MRS Assessment Report No. 6, p. 1)

Discussion and Commission Determination

After reviewing the materials provided in connection with MRS Assessment Report No. 6, the Commission is of the view the nine Revised Standards assessed by BC Hydro are required to maintain or achieve consistency in BC with other jurisdictions that have adopted the reliability standards. The Commission **adopts the nine Revised Standards in accordance with subsection 125.2(6) of the Act**. **The effective dates for the revised standards are**

as laid out in the table found in Attachment A to this Order. Each standard to be superseded by a standard adopted in this Order shall remain in effect until the effective date of the standard superseding it.

The Commission accepts BC Hydro's recommendation that the December 5, 2012 NERC Glossary of Terms is suitable for adoption in BC as it will maintain or achieve consistency with NERC standards going forward. **The Commission adopts the NERC Glossary of Terms Used in Reliability Standards, dated December 5, 2012, which defines terms employed in the reliability standards. The effective date of each of the new or revised glossary terms adopted in this Order is the date appearing in the table found in Attachment A to this Order. Each glossary term to be superseded by a revised glossary term adopted in this Order shall remain in effect until the effective date of the glossary term superseding it.**

The Commission also notes the inconsistencies noted in MRS Assessment Report No. 6 and, in order to provide clarification, directs the adoption of the effective dates included in Appendix D – Draft Order; Attachment B of the Report, as amended by the Errata. **As a result of this Order and Orders G-67-09, G-167-10, G-162-11, G-175-11, R-1-13 and R-11-13, the standards listed in the table found in Attachment B to this Order are all of the reliability standards in effect in British Columbia as of the effective dates listed in Attachment B to this Order and the effective dates for the reliability standards that are listed in the table found in Attachment B supersede the effective dates that were included in any similar list appended to any previous order.**

The Commission adopts the NERC Glossary of Terms Used in Reliability Standards, dated December 5, 2012, which defines terms employed in reliability standards. The effective date of each of the new or revised glossary terms adopted in this Order is the date appearing in the table found in Attachment A to this Order. Each glossary term to be superseded by a revised glossary term adopted in this Order shall remain in effect until the effective date of the glossary term superseding it.

Terms within the NERC Glossary of Terms used in Reliability Standards, dated December 5, 2012 that do not include a U.S. FERC approval date on or before November 30, 2012 are of no force or effect in BC.

The Commission understands that BC Hydro does not assess the compliance provisions that accompany the various reliability standards. The Commission considers the compliance provisions that accompany the reliability standards helpful for compliance monitoring in BC. The Commission also finds it appropriate to provide effective dates for entities to come into compliance with the reliability standards and Glossary Terms adopted in this Order. **The Commission adopts the Compliance Provisions, as defined in the Rules of Procedure for Reliability Standards in British Columbia, that accompany each of the adopted reliability standards, in the form directed by the Commission and as amended from time to time.**

The reliability standards adopted in BC by the Commission will be posted on the WECC website with a link from the Commission website.

4.0 BC HYDRO'S PROCESS FOR ASSESSING STANDARDS AND REQUIREMENTS OF STANDARDS

In this section the Commission discusses BC Hydro's process for assessing reliability standards and provides reasons for Directive 10 of Order R-41-13. Directive 10 states: "BC Hydro must provide a report on reliability standards, in accordance with the Act, within one year of the date the reliability standards are adopted by FERC. In assessing standards, BC Hydro should recommend appropriate BC effective dates to allow entities to come into compliance with the reliability standards within a reasonable time period."

There are two central issues, relevant to Directive 10, to be addressed. First, is BC Hydro's process for assessing reliability standards which hinges on the interpretation of the word "adopted" in subsection 3(1) of the MRS Regulation. Second is BC Hydro's proposal to further refine its assessment process for requirements of reliability standards.

4.1 BC Hydro's Process for Assessing Standards

In MRS Assessment Report No. 6, BC Hydro described its assessment process to date and proposed further refinement of its assessment process for requirements of reliability standards. In considering BC Hydro's proposal for refining its assessment process for requirements of reliability standards, the Commission considered relevant sections of the Act and MRS Regulation as well as BC Hydro's historical approach to reviewing standards.

Section 3 – Reports, of the MRS Regulation states:

> 3(1) Subject to subsection (2), a report on a reliability standard, prepared by the transmission corporation in accordance with section 125.2 (3) of the Act, must be provided to the commission within one year of the later of the following dates:
>
> > (a) the date the reliability standard is adopted by the regulatory body with jurisdiction over the standard-making body that established the reliability standard;
> >
> > (b) the date this regulation comes into force.
>
> (2) On application by the transmission corporation, the commission may extend the time by which the transmission corporation must provide a report under subsection (1).

BC Hydro indicates the approach taken in previous MRS assessment reports and used for this MRS Assessment Report No. 6 has been to interpret "adopted" in the MRS Regulation as meaning those standards that are FERC approved and become enforceable under U.S. law during the relevant Assessment Period (Exhibit B-1, section 4.1 - Identification of Standards for Review and Inclusion in MRS Assessment Report No. 6, p. 11, line 10-13). BC Hydro's approach for assessing standards, both new and revised, has been to assess those standards that are adopted by FERC and become enforceable in the U.S. within BC Hydro's annual assessment period of December 1 to November 30 (Exhibit B-1, MRS Assessment Report No. 6, Section – 2.1 Assessment Process for Requirements, p. 2, lines 15-21). BC Hydro indicates this approach was taken in previous MRS assessment reports and used for MRS Assessment Report No. 6 (Exhibit B-1, MRS Assessment Report No. 6, Section 4.1 – Identification of Standards for Review and Inclusion in MRS Assessment Report No. 6, p. 11, lines 10-13).

BC Hydro states the rationale for BC Hydro's delayed assessment, following U.S. enforceability, is to allow U.S. experience to inform the assessment of reliability standards for suitability in BC (Exhibit B-1, MRS Assessment Report No. 6 Section 2.1 – Assessment Process for Requirements, p. 2, lines 15-21). BC Hydro submits that entities in BC benefit from the delayed assessment of reliability standards because they have the benefit of regulatory certainty and can ensure that reliability standards adopted in BC align with those in the U.S. (Exhibit B-4, BC Hydro response to BCUC IR No. 1.1.2, p. 2). BC Hydro also submits the benefits of waiting until a reliability standard is enforceable in the U.S., "outweigh the perceived disadvantages associated with the inconsistency" (Exhibit B-4, BC Hydro response to BCUC IR No. 1.1.8, p. 3).

BC Hydro notes:

> "[t]here is often a time lag between the date upon which FERC approves a reliability standard and the date on which that reliability standard becomes mandatory and enforceable in the U.S. During this time, uncertainty with respect to the implementation of the reliability standard can arise. For example, entities can challenge a decision by FERC to approve a reliability standard and request a rehearing; similarly, if there are implementation issues, entities can request extensions to the effective date to allow time to properly plan the implementation" (Exhibit B-4, BC Hydro Response to BCUC IR No. 1.1.2, p. 2).

BC Hydro also submits that the time lag resulting from delayed assessment does not result in a reliability gap for BC entities (Exhibit B-4, BC Hydro response to BCUC IR No. 1.1.6, p. 2). Further, BC Hydro states: "If BC Hydro determines that a new or revised standard is sufficiently critical to transmission system reliability that it warrants immediate implementation, BC Hydro would file a reliability standard specific assessment report and not wait for the next assessment period" (Exhibit B-4, BC Hydro response to BCUC IR No. 1.1.7, p. 2).

Discussion and Commission Determination

The term at the centre of this discussion is "adopted" in subsection 3(1)(a) of the MRS Regulation.

Subsection 125.2(1) of the Act defines a standard making body as: (a) NERC, (b) WECC and (c) a prescribed standard-making body. Subsection 125.2(3) of the Act and subsection 3(1)(a) of the MRS Regulation require BC Hydro to provide a report assessing a reliability standard within one year of the date the reliability standard is adopted by the regulatory body with jurisdiction over the standard-making body that established the reliability standard (NERC, WECC or other standard-making body). The regulatory body with jurisdiction over NERC and WECC is the U.S. FERC.

As noted in MRS Assessment Report No. 6, and previous assessment reports, BC Hydro has interpreted the word "adopted" in subsection 3(1)(a) of the MRS Regulation to mean those standards which are both approved and which become enforceable under U.S. law within BC Hydro's annual Assessment Period (Exhibit B-1, Section 4.1, p. 11, lines 10-13).

The Commission is not persuaded that the term "enforceable" is relevant to the interpretation of the term "adopted" as it pertains to the MRS Regulation. Section 215 of the *Federal Power Act* requires NERC as the Electric Reliability Organization to develop mandatory and enforceable reliability standards, which are subject to FERC review and approval in the U.S. FERC-approved reliability standards become mandatory and enforceable in the U.S. on a date established in the FERC Orders approving the standards.[1]

On its website, NERC defines "Enforcement Date" as "the date on which the standard becomes mandatory and enforceable in accordance with the existing laws of the jurisdiction and the approval granted by the regulatory authority."[2]

The NERC process has evolved and with this evolution the Commission observes there are instances where the time between FERC Orders approving reliability standards and the date the reliability standards become

[1] See NERC Website http://www.nerc.net/standardsreports/standardssummary.aspx
[2] See NERC Website for Definitions and Enforcement Dates http://www.nerc.net/standardsreports/standardssummary.aspx

enforceable has increased. See for example reliability standard PRC-023-2 – Transmission Relay Loadability which provides for staggered effective dates for requirements.[3]

The Commission observes there are two dates relating to FERC Orders which are particularly relevant to this discussion and which inform the Commission's interpretation of the term "adopted" in subsection 3(1) of the MRS Regulation. The first date is located at the top of FERC Order and is the Issued Date of the FERC Order (i.e. Order Issued Date). The second date is the "Effective Date" of the FERC Order.

FERC Orders generally come into effect in one of three ways. First, the FERC Order may explicitly state the Order is effective on a particular date (e.g. "This Order is effective March 1, 2014"). Second, the FERC Order may be silent on the date, in which case the effective date is the Order Issued Date from FERC. Finally, FERC Orders often specify an Effective Date that is either the Publication Date or a date later than the Publication Date in the Federal Register.

The Commission considers a reliability standard to be "adopted" in the U.S. by FERC on the date of regulatory approval. As noted this may be the Issued Date, the Effective Date or another specified date that is on or after the Publication Date of the FERC Order. It may be possible for the FERC Order Effective Date to coincide with the Enforcement Date defined by NERC. Although, in some cases the Enforcement Date may be a date further in the future.

For example, FERC Order No. 793 approving reliability standard PRC-005-2 - Protection System Maintenance, has an Issued Date of December 19, 2013. FERC Order No. 793 was published in the Federal Register on December 24, 2013. The Order stipulates an Effective Date: "This rule will become effective [**insert date 60 days after publication in the FEDERAL REGISTER**]." Based on the date of publication in the Federal Register (December 24, 2013) FERC Order No. 793 has an Effective Date of February 24, 2013. Further, on NERC Website under U.S. Enforcement Dates, NERC Notes section indicates "the implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the requirements. For purposes of calculating the time periods in the implementation plan, the regulatory approval date in the U.S. is February 24, 2014."[4] Thus, for consistency, the Commission considers the reliability standard to be "adopted" in the U.S. as of February 24, 2013.

Based on this interpretation, FERC Order No. 793 took effect and reliability standard PRC-005-2 – Protection System Maintenance, would be considered to have been approved by FERC within BC Hydro's December 1, 2013 to November 30, 2014 Assessment Period. Accordingly, the Commission would anticipate the reliability standard would be included in the 2014 Assessment Report and reported on to the Commission by April 30, 2015.

Thus, **BC Hydro must provide a report on reliability standards, in accordance with the Act, within one year of the date the reliability standards are adopted by FERC. In assessing standards, BC Hydro should recommend appropriate BC effective dates to allow entities to come into compliance with the reliability standards within a reasonable time period.**

There is some administrative stability in BC Hydro's historical approach to assessing reliability standards. However, the Commission is not convinced enforceability is applicable to the interpretation of the term "adopted" in the MRS Regulation. FERC Orders may be reconsidered and reliability standards altered both before and after a relevant FERC Enforcement Date for a particular standard. To the extent there may be any

[3] See NERC Effective Dates attached in Appendix A-2 – NERC Standards Assessed by BC Hydro Clean, p. 36, MRS Assessment Report No. 6
[4] See NERC Website under Program Areas & Departments, Standards Subject to Future Enforcement

concern that a standard may be in forced in BC before the NERC Enforcement Date, the Commission notes that it would expect BC Hydro to recommend a BC effective date that would not result in this situation.

If BC Hydro is of the view that entities in BC would significantly benefit from delayed assessment of a specific reliability standard then BC Hydro may apply to the Commission for an extension to the time by which it must provide a report under subsection 3(1) of the MRS Regulation. Similarly, BC Hydro may suggest a delayed effective date. In any such Application, the Commission would expect BC Hydro to confirm there is no adverse impact to reliability as a result of delayed implementation and provide the reasons for and/or benefits to postponing the assessment of a reliability standard. Ultimately, the Commission relies on BC Hydro's assurance that it will identify standards that are sufficiently critical to reliability as to warrant immediate implementation; and in these instances, BC Hydro would not wait for the next batch assessment report, but rather bring forward a standard-specific assessment for immediate implementation.

4.2 BC Hydro's Proposed Process for Assessing Requirements of Standards

In this section, the Commission addresses BC Hydro's proposal relating to its assessment process for individual requirements of reliability standards.

In MRS Assessment Report No. 6, BC Hydro proposed that since some NERC reliability standards are now developed with staged requirement effective dates, BC Hydro would further refine its assessment process.

> "Specifically, BC Hydro proposes any standards that contain at least one requirement that becomes FERC approved and enforceable within the relevant Assessment Period will be assessed and reported in the annual MRS assessment report. The assessed standard will still contain the language of all the requirements but will only show BC effective dates for the requirements being assessed in that Assessment Period. BC Hydro proposes to assess the remainder of the requirements individually, and to suggest BC effective dates once each requirement becomes enforceable in the U.S." (Exhibit B-1, MRS Assessment Report No. 6, Section 2.1 Assessment Process for Requirements, p. 2, lines 1-7 and p.3 lines 25-27).

BC Hydro is of the view that "[t]he definition of 'reliability standard' in the Act is sufficiently flexible to enable BC Hydro to adapt its assessment approach as is needed to align with NERC's changing approach in creating and implementing new reliability standards" (Exhibit B-4, BC Hydro Response to BCUC IR No. 1.3.1, p. 2).

Further, BC Hydro describes how in Assessment Report No. 1 BCTC split the NERC reliability standards into two components. The first component is the "reliability standard" under the Act and the second component is the compliance-related provisions that accompany but are not held to be the "reliability standard." This is also specified in the Commission's *Rules of Procedure for Reliability Standards in BC* (BC ROP).[5] BC Hydro indicates the described separation of reliability standards from the compliance provisions is akin to its proposal to assess individual requirements. Ultimately, BC Hydro submits that each requirement contained within a reliability standard could be argued to be either a "reliability standard" or a "rule" as contemplated in the definition in the Act and therefore BC Hydro would assess individual requirements in a staged way (Exhibit B-4, BC Hydro response to BCUC IR No. 1.3.1, p. 3).

[5] See Section 2 – Definitions of BC ROP, for definitions for "Reliability Standard" and "Compliance Provisions"

Discussion and Commission Determination

The Commission is not persuaded by BC Hydro's proposal to further refine its approach by assessing individual requirements of reliability standards only as they become enforceable in the U.S. First, the Commission has previously determined that the "trigger date" for review of reliability standards by BC Hydro is the Effective Date of the FERC Order approving the reliability standard in the U.S. This is a matter of interpretation of the word "adopted" used in subsection 3(1) of the MRS Regulation and is dealt with in section 2.1 of these Reasons for Decision. Secondly, the Commission is not convinced the proposed staged assessment process is appropriate in reference to the Act, the MRS Regulation, and the BC ROP. Thirdly, the Commission sees benefit to assessing individual Requirements at the same time. Finally, the Commission notes the proposed refined process appears to be inconsistent with BC Hydro's approach relating to the NERC Glossary of Terms.

Subsection 125.2(1) of the Act defines a "reliability standard" as:

> *"a reliability standard, rule or code established by a standard-making body for the purpose of being a mandatory reliability standard for planning and operating the North American bulk power system, and includes any substantial change to any of those standards, rules or codes."*

Section 2 – Definitions, of the BC ROP defines the term "Compliance Provisions" as:

> *"The compliance-related provisions that accompany, but do not constitute part of, a Reliability Standard and that have been adopted by the Commission. For clarity, Compliance Provisions adopted by the Commission may differ from the compliance or enforcement provisions accompanying reliability standards of a standard- making body prescribed in the Act (i.e. NERC or WECC)."*

Further in section 2, the BC ROP defines "reliability standard" as:

> *A reliability standard as defined in Section 125.2(1) of the Act that has been adopted by the Commission under Section 125.2(6) of the Act for application in British Columbia. A Reliability Standard normally consists of the following components: (i) Introduction; (ii) Requirements; and (iii) Measures. A Reliability Standard does not include Compliance Provisions.*

The Commission recognizes this distinction between the reliability standard and the compliance-related provisions is consistent with the definitions in the BC ROP. The Commission is not supportive, however, of BC Hydro's proposal to split reliability standards into separate Standards based on individual requirements, for assessment purposes.

After considering the definitions provided in the Act and the BC ROP, the Commission is of the view that the requirements of reliability standards are part of one reliability standard as defined by the Act and addressed in the BC ROP and that requirements and/or reliability standards should be assessed by BC Hydro in their entirety in accordance with the Act and the MRS Regulation.

When NERC files a Petition for FERC approval of a reliability standard that Petition includes an implementation plan which may allow for a transitional period of time for U.S. entities to conform with Requirements of the new or revised reliability standard. In the cases where NERC proposes phased effective dates for requirements of a new or revised standard, FERC may approve the phased approach. In such cases FERC adopts the reliability standard in its entirety as opposed to the individual requirements of that particular Standard. In addition, while BC Hydro points out in MRS Assessment Report No. 6 that FERC may also direct NERC to develop or consider a number of modifications to the approved standard, in these cases the Commission observes that the reliability standard remains approved as is until the revised version is approved by FERC.[6] Thus, the proposal to assess individual requirements of reliability standards does not appear to be consistent with U.S. practice.

Phased or staggered requirements effective dates are available for individual requirements to allow a transitional period of time within which entities can achieve full compliance with the various requirements of a reliability standard. For example, FERC Order No. 693 states that modifications to existing reliability standards should include proposed effective dates that "take into account any time needed for users, owners and operators of the Bulk-Power System to incorporate the necessary changes" (FERC Order No. 693, p. 61).

This matter was addressed by FERC Order No. 742 wherein FERC considered NERC's proposed use of staggered effective dates for the two proposed reliability standards, which modify currently effective standards. The FERC questioned whether staggered effective dates could create a gap in compliance and enforceability and also questioned the need for the proposed two-and three-year lead times before certain Requirements in PER-005-1 became mandatory and enforceable. Ultimately, FERC found the proposed staggered implementation schedule for reliability standard PER-005-1 and PER-004-2 and the corresponding retirement schedule for PER-002-0 and PER-004-1 struck a reasonable balance between the need for timely reform and the needs of the entities subject to PER-005-1 to develop and implement training programs utilizing a systematic approach to training and use of simulators as a training tool.[7]

Finally, the Commission observes that BC Hydro's suggested approach would also appear to be inconsistent with the approach to assessing NERC Glossary of Terms that are approved by FERC during the Assessment Period, whether or not they become effective. Regarding the NERC Glossary of Terms BC Hydro states in Section 2.1 – Assessment Process for Requirements of MRS Assessment Report No. 6,

> "BC Hydro considers it appropriate that the BCUC adopt the most current Glossary adopted by NERC during the annual assessment period. BC Hydro proposes that it will assess those defined terms in the Glossary that were FERC approved during the Assessment Period, whether or not they became effective, and will make recommendations for effective dates of new or revised defined terms where appropriate. This is consistent with BCUC Order No. R-1-13 dated January 15, 2013 which directed in Directive 10 that 'definitions within the NERC Glossary used in reliability standards, dated December 13, 2011, which have not been approved by the U.S. Federal Energy Reliability Commission, are of no force or effect.' This will allow versions of the NERC Glossary to be adopted in their entirety in advance of any new or revised defined terms contained in them being required in B.C., and avoids maintaining a 'B.C. only' glossary of terms." (Exhibit B-1, MRS Assessment Report No. 6, Section 2.1 – Assessment Process for Requirements, p. 3, lines 8-23)

The Commission is of the view that by not assessing requirements of reliability standards until they become effective and enforceable in the U.S., BC Hydro may be generating regulatory uncertainty and inconsistency with other jurisdictions that have adopted reliability standards in full, albeit with later requirements effective dates.

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[6] FERC Order No. 693 ordered significant improvements to 56 of 83 Reliability Standards being approved as mandatory and enforceable. See FERC Order No. 693 http://www.ferc.gov/whats-new/comm-meet/2007/031507/E-13.pdf though the Reliability Standards remained approved.

[7] See FERC Order No. 742 – System Personnel Training Reliability Standards http://www.ferc.gov/whats-new/comm-meet/2010/111810/E-8.pdf

Accordingly, BC Hydro should provide a report assessing all of the sections of a reliability standard (i.e. including the introduction, requirements and measures but not accompanying compliance-related provisions) and recommend BC effective dates that allow BC entities to come into compliance with the reliability standard in a reasonable period of time. The effective dates may take into consideration the phased implementation approach employed by NERC and accepted by FERC.

For the reasons stated above, **BC Hydro must provide a report on reliability standards, in accordance with the Act, within one year of the date the reliability standards are adopted by FERC. In assessing standards, BC Hydro should recommend appropriate BC effective dates to allow entities to come into compliance with the reliability standards within a reasonable time period.**

5.0 WECC CRITERIA AND RELIABILITY STANDARD PRC-004-2A

BC Hydro identified Revised Standard PRC-004-2a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations as a Revised Standard to be assessed under MRS Assessment Report No. 6. Requirements 1, 2 and 3 of reliability standard PRC-004-2a refer to "Regional Entity Procedures."

In MRS Assessment Report No. 6, BC Hydro indicated,

> *"On May 21, 2013, WECC issued an email to its "Compliance Contacts" that introduced a new BC Misoperation Reporting Webpage. BC Hydro is unclear as to whether this webpage is meant to constitute the 'Regional Entity's Procedures' as contemplated In PRC-004-2a. BC Hydro requests that the BCUC clarify what constitutes the 'Regional Entity's Procedures' for compliance purposes.*
>
> *Accordingly, BC Hydro is not in a position to recommend that this Revised Standard be adopted in B.C. at this time. BC Hydro recommends that, following clarification of the 'Regional Entity's Procedures', this Revised Standard be re-assessed and a recommendation regarding its suitability for adoption be made at that time"* (Exhibit B-1, MRS Assessment Report No. 6, Section 2.3 – PRC-004-2a, p. 6, lines 7-18).

The Commission's letter dated July 3, 2013 attached the WECC's Regional Criterion PRC-003-WECC-CRT-1.2 with errata dated June 26, 2013 and corresponding reporting template (together, the WECC Criterion) and clarified that the WECC Criterion described the procedures for reporting under PRC-004-2a.

In addition Recital D of Commission Order R-30-13 posted as Exhibit A-1 on the Commission's Website states the following: "In a letter dated July 3, 2013, the Commission provided BC Hydro with the Western Electricity Coordinating Council's (WECC) criterion PRC-003-WECC-CRT-l and the corresponding reporting template, which together describe the procedures for reporting under PRC-004-2a. In the same letter, the Commission requested BC Hydro to provide the assessment of PRC-004-2a as an Addendum to the Report as soon as possible, and the Commission expects this Addendum will be provided in September 2013..."

BC Hydro filed the Addendum in accordance with Order R-30-13 on September 30, 2013. In the Addendum, BC Hydro stated:

> "BC Hydro recommends that PRC-004-2a be adopted by the BCUC and further recommends that its effective date should be based on the recommended effective date included in Table 3, section 5.3.

Further, on May 16, 2013, the BCUC issued Letter No. L-28-13, requesting that BC Hydro review the extent to which WECC regional criteria may be sufficiently developed to enable standards requirements that refer to those not-yet-approved standards to be brought into force in BC. This review will assist in determining the applicability of regional criteria and not-yet-approved standards in future MRS assessment reports.

As suggested in BC Hydro's submission in response to BCUC issued Letter No. L-28-13, BC Hydro recommends that the BCUC adopt PRC-004-2a and, to the extent it agrees with BC Hydro's submission, that the BCUC issue an order directing B.C. registered entities to comply with the WECC Criteria in order to demonstrate compliance with PRC-004-2a." (Exhibit B-2, Addendum to MRS Assessment Report No. 6, Section 10 – Conclusions, p. 13, paras. 2-4)

Discussion and Commission Determination

The Commission acknowledges BC Hydro's recommendation that the Commission issue an Order requiring BC entities to comply with WECC Criteria PRC-003-WECC-CRT-1.2 which describes procedures for reporting under PRC-004-2a and appreciates BC Hydro's desire for clarity.

The Commission agrees with BC Hydro's recommendation that clarity should be provided to BC entities and finds it useful to discuss the reference to "Regional Entity Procedures" made in the NERC and WECC materials.

First, Section 313 of the NERC Rules of Procedure for Reliability Standards (effective October 4, 2013) defines Regional Criteria as:

> "Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC reliability standards, but which are not reliability standards. Regional Criteria may also address issues not within the scope of reliability standards, such as resource adequacy. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents used to enhance the reliability of the Bulk Power System in the Region. These documents typically provide benefits by promoting more consistent implementation of the NERC reliability standards within the Region. These documents are not NERC reliability standards, Regional reliability standards, or regional Variances, and therefore are not enforceable under authority delegated by NERC pursuant to delegation agreements and do not require NERC approval."[8]

Further, in WECC's Document Categorization Policy, approved June 27, 2013[9], WECC defines Regional Criteria as:

> "A WECC Regional Criterion is a WECC Board-approved document, applicable only in the Western Interconnection, created to establish requirements to address NERC 'Fill-In-The-Blank' reliability standards or necessary to implement, to augment, or to comply with NERC or Regional reliability standards or requirements under programs established by the Applicable Governmental Authority in Canada and Mexico, as applicable."

[8] See NERC Rules of Procedure, effective October 4, 2013, section 313, p. 16
[9] See WECC Document Categorization Policy on WECC's Website at: http://www.wecc.biz/library/Documentation%20Categorization%20Files/Policies/Document%20Categorization%20Policy.pdf

The WECC Document Categorization Policy also notes in its "Applicability" section that "WECC Regional Criteria are applicable to entities in Canada and Mexico as determined by the Applicable Governmental Authority." Under the "Monitoring and Enforcement" section, it states: "Regional Criteria are not enforceable under authority delegated by NERC. However, if a FERC approved reliability standard references a regional procedure, plan, process, etc. a Registered Entity may be found in violation of that Standard for not following the applicable requirements in a Regional Criterion."

Item 7 of the Administrative Agreement between WECC and the Commission: U.S. Law, U.S. Reliability Standards, and NERC/WECC Policies and Procedures,[10] states:

> "The policies, rules of procedure, functional registration manuals, and compliance monitoring and enforcement policies and procedures, and other documents of NERC and WECC **in relation to U.S. reliability standards** shall have no application in British Columbia except to the extent that they are expressly incorporated by reference into the Rules of Procedure, the Registration Manual, the Compliance Monitoring Program, or otherwise adopted by British Columbia legislation or regulation or by an Order of the BCUC." [Emphasis added]

Item 7 of the Administrative Agreement between WECC and the Commission may seem to have implications for applicability of WECC Criteria in BC. Also, the Rules of Procedure for the BC MRS Program, including the Registration Manual and Compliance Monitoring Program, do not explicitly reference the Regional Criteria. However, the Commission observes as indicated in the references above that the Regional Criteria are created by WECC with a view to application throughout the Western Interconnection including "under programs established by the Applicable Governmental Authority in Canada." Rather, the published materials state clearly that WECC Regional Criteria are designed to be "applicable to entities in Canada and Mexico as determined by the Appropriate Regulatory Authority." As such, the Commission considers the Regional Criteria may not be restricted to being "in relation to U.S. reliability standards" for purposes of Item 7 of the Administrative Agreement.

The Commission is not persuaded that addressing the issue through a specific order requiring entities to comply with WECC Criteria PRC-003-WECC-CRT-1.2 is necessary, nor that such an order would be the most efficient mechanism to provide clarity for BC entities. There may be efficiencies gained from including the matter of Regional Criteria as part of the suggested revisions to the BC ROP. However, the Commission considers further process, independent of this MRS Assessment Report No. 6, to be appropriate to fully consider BC Hydro's proposal included in its October 18, 2013 response to Commission letter to L-28-13.[11]

In the meantime, as recommended by BC Hydro, the Commission adopts reliability standard PRC-004-2a by Order R-41-13. With these Reasons for Decision, the Commission confirms that BC entities should comply with the WECC Criterion PRC-003-WECC-CRT-1.2 for the purposes of demonstrating compliance with Standard PRC-004-2a.

6.0 PLANNING COORDINATOR AND RELIABILITY STANDARD PRC-023

On April 18, 2013, BC Hydro submitted a letter to the Commission regarding concerns relating to the role of Planning Coordinator (PC) in BC. BC Hydro indicated in MRS Assessment Report No. 6, "The issue was brought to

[10] The Administrative Agreement is included as Attachment 2 of Commission Order G-123-09
[11] Commission letter L-28-16 is available on the Commission's Website.

BC Hydro's attention through the assessment process for PRC-023-2. A number of entities noted that in order to assess Requirement 6 of the Revised Standard PRC-023-2, they would need to know which of a registered entity's assets are identified as 'critical' by a PC" (Exhibit B-1, MRS Assessment Report No. 6, Section 2.2 – Planning Coordinator and PRC-023-2, p. 4, lines 21-24).

The Commission issued letter L-29-13A[12] on May 22, 2013 in response to BC Hydro's letter dated April 18, 2013. The Commission's letter sought input from BC Hydro and other registered entities as to "the extent of the Planning Authority (PA)/PC operations/footprint in BC."

In MRS Assessment Report No. 6, BC Hydro submits:

> "BC Hydro respectfully submits that until it is clear what the 'footprint' for a PC will be in B.C. and, as a result, whether there will be more than one PC in B.C., it is not appropriate to have standards in effect that impose unique obligations on a PC. From BC Hydro's perspective, assuming that BC Hydro is a PC because of its registration as a planning authority in B.C., BC Hydro cannot properly perform its function until the issue of the applicable footprint is resolved" (Exhibit B-1, MRS Assessment Report No. 6, Section 2.2, Planning Coordinator and PRC-023-2, p. 5, lines 4-10).

For the purposes of MRS Assessment Report No. 6,

> "BC Hydro is recommending that only those requirements of PRC-023-2 that do not rely on actions being taken by the PC be adopted in B.C. However, for those requirements that depend on the PC, BC Hydro recommends that appropriate effective dates be determined by the BCUC following the submissions by BC Hydro and other registered entities in July 2013. In its submission, BC Hydro will provide suggested effective dates; however these dates will reflect BC Hydro's position only. Other entities that may perform the PC role in B.C. should also feel free to suggest dates in their submissions as well" (Exhibit B-1, MRS Assessment Report No. 6, Section 2.2, Planning Coordinator and PRC-023-2, p. 5, lines 11-18).

In addition,

> "BC Hydro suggests that, with the exception of Requirement 3, the requirements of BCUC approved standard PRC-023-1 – Transmission Relay Loadability should remain in effect until superseded in stages by the requirements of Standard PRC-023-2. BC Hydro also respectfully recommends that the effective date of PRC-023-1, Requirement 3 should be rescinded and either re-established following the July 2013 submissions or replaced through the implementation of PRC-023-2 Requirement 6. Accordingly, BC Hydro is seeking an order from the BCUC to rescind the effective date for Requirement 3 of PRC-023-1 as established under order G-162-11 until such time as a new effective date is determined" (Exhibit B-1, MRS Assessment Report No. 6, Section 2.2, Planning Coordinator and PRC-023-2, p. 5, lines 19-27).

In Response to Commission IR No. 1.6.8, BC Hydro confirms "BC Hydro is fully performing the PA and PC functions for its own footprint at this time. BC Hydro has reviewed the corresponding reliability standards

[12] Commission letter L-29-13A is available on the Commission's Website. The letter was distributed to all registered entities in the BC MRS Program.

requirements and evaluated its existing processes to ensure compliance for its own asset footprint" (Exhibit B-4, BC Hydro response to BCUC IR No. 1.6.8, p. 1).

Discussion and Commission Determination

The Commission finds the PA/PC question is beyond the scope of MRS Assessment Report No. 6 review process. Accordingly, the Commission considers it appropriate to establish a separate process in early 2014 to consider the PA/PC matter as it pertains to BC.

The Commission accepts BC Hydro's request to rescind the effective date for Requirement 3 of standard PRC-023-1 (removing the Effective Date as noted in Appendix B of Order R-41-13) and BC Hydro's recommendation regarding PRC-023-2. The Commission's acceptance of BC Hydro's request is reflected through Directives 1, 2 and 4 of Order R-41-13 and the effective dates noted in the tables found in Attachment A and Attachment B to the Order. Once the PA/PC matter has been clarified as requested, the Commission may order BC Hydro to re-assess PRC-023-1 and PRC-023-2 at a future date and to recommend BC Effective Dates.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of January, 2014.

Original Signed By:
D.M. MORTON
COMMISSIONER