British Columbia Utilities Commission
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ORDER NUMBER
R-9-25A

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority
Mandatory Reliability Standards Assessment Report No. 18

BEFORE:
E. A. Brown, Commissioner
A. K. Fung, KC, Commissioner
E. B. Lockhart, Commissioner

on July 30, 2025

ORDER

WHEREAS:

A. On April 30, 2025, pursuant to section 125.2(3) of the *Utilities Commission Act* (UCA), British Columbia Hydro and Power Authority (BC Hydro) submitted to the British Columbia Utilities Commission (BCUC) Mandatory Reliability Standards (MRS) Assessment Report No. 18 (Report). The Report assesses one new and five revised reliability standards (Revised Standards), seven new and thirty revised terms from the North American Electric Reliability Corporation (NERC) Glossary of Terms dated November 4, 2024 (Revised Terms) and four retired NERC Glossary terms (Retired Terms). BC Hydro recommends that the Revised Standards and Revised Terms be adopted in BC and the Retired Terms be retired in BC;

B. By Order R-5-25 dated May 29, 2025, the BCUC established a regulatory timetable for a proceeding to review the Report. The regulatory timetable included notice to all entities registered in BC's MRS program (Entities) and a comment process;

C. On June 20, 2025, FortisBC Inc. (FBC) submitted a letter of comment confirming that its feedback is reflected in the Report and that it has no additional comments regarding the Report;

D. On June 26, 2025, in compliance with Directive 12 of BCUC Order R-24-22A1, BC Hydro filed Quarterly Assessment Report No. 10 (Quarterly Report) for the reporting period of March 1, 2025 to May 31, 2025. In the Quarterly Report, BC Hydro states that the Federal Energy Regulatory Commission (FERC) approved reliability standard BAL-004-WECC-4. BC Hydro categorizes it as a critical standard and, accordingly, recommends an accelerated adoption of BAL-004-WECC-4 with a proposed effective date of October 1, 2025, to align with the effective date in the United States;

E. By Order R-8-25 dated July 3, 2025, the BCUC included the Quarterly Report and reliability standard BAL-004-WECC-4 in the Assessment Report No. 18 proceeding with an amended regulatory timetable to provide an opportunity for comments on the Quarterly Report and the adoption of BAL-004-WECC-4;

F. On July 9, 2025, FBC submitted a letter of comment confirming that it has no concerns with the accelerated adoption of BAL-004-WECC-4 as proposed by BC Hydro;

G. On July 15, 2025, BC Hydro filed its reply to letters of comment stating that to date, no other public comments have been received. BC Hydro submits that based on the Entities' feedback on Assessment Report No. 18, it recommends the proceeding can now advance to the decision phase;

H. In the Report, BC Hydro states that it did not assess compliance-related provisions (Compliance Provisions) in the standards because they are not mandatory reliability standard requirements;

I. The BCUC has not reviewed the recoverability of the estimated costs to adopt the Revised Standards and Revised Terms;

J. Pursuant to section 125.2(6) of the UCA, the BCUC must adopt the reliability standards and glossary terms addressed in the Report and the Quarterly Report if the BCUC considers that the reliability standards are required to maintain or achieve consistency in BC with other jurisdictions that have adopted the reliability standards, unless the BCUC determines under section 125.2(7), after a hearing, that the reliability standards are not in the public interest;

K. The BCUC has reviewed and considered the Report, the Quarterly Report, and submissions in this proceeding and determines that adoption of the recommendations in the Report and Quarterly Report is warranted, with BC implementation plans as proposed;

L. Although not assessed by BC Hydro, the BCUC finds that the Compliance Provisions of the reliability standards should be adopted to maintain compliance monitoring consistency with other jurisdictions that have adopted the reliability standards with the Compliance Provisions. The BCUC also considers it appropriate to provide effective dates for Entities to come into compliance with the Revised Standards and Revised Terms adopted in this order; and

M. On July 30, 2025, the BCUC issued Order R-9-25. The present Order R-9-25A is being issued to correct a typographical error in the effective date of reliability standard VAR-501-WECC-4 set out in Attachments A and D of Order R-9-25, and replaces Order R-9-25.

NOW THEREFORE pursuant to sections 125.2(3) and 125.2(6) of the UCA, the BCUC orders as follows:

1. Revised Standards BAL-004-WECC-4, CIP-012-2, EOP-011-4, EOP-012-2, FAC-501-WECC-4, TOP-002-5 and VAR-501-WECC-4 assessed in the Report and the Quarterly Report are adopted with effective dates as identified in Attachment A to this order.

2. Each standard to be superseded by a Revised Standard adopted in this order shall remain in effect until the effective date of the Revised Standard superseding it.

3. The Revised Terms assessed in the Report are adopted with effective dates as identified in Attachment B to this order.

4. Each NERC Glossary term to be superseded by a Revised Term adopted in this order shall remain in effect until the effective date of the Revised Term superseding it.

5. The four Retired Terms are retired with effective dates as identified in Attachment B to this order.

6. All reliability standards listed in Attachment A to this order are effective in BC as of the dates shown. The effective dates for the reliability standards listed in Attachment A supersede the effective dates that were included in any similar list appended to any previous order of the BCUC.

7. Individual requirements and requirement parts in reliability standards that incorporate by reference reliability standards that have not been adopted by the BCUC are of no force or effect in BC, and individual requirements or requirement parts in reliability standards that the BCUC has adopted but for which the BCUC has not determined an effective date, are of no force or effect in BC.

8. Defined terms in the reliability standards bear the same meanings as those in the NERC Glossary of Terms dated November 4, 2024. Terms in the NERC Glossary of Terms, which do not include a FERC approval effective date on or before November 30, 2024, are of no force or effect in BC.

9. Except for the Retired Terms, all NERC Glossary terms listed in Attachment B to this order are in effect in BC as of the effective dates indicated.

10. The BC implementation plans for reliability standards EOP-011-4 and EOP-012-2 are adopted in BC as set out in Attachment C to this order.

11. The reliability standards BAL-004-WECC-4, CIP-012-2, EOP-011-4, EOP-012-2, FAC-501-WECC-4, TOP-002-5 and VAR-501-WECC-4 in their written form are adopted as set out in Attachment D to this order.

12. The Compliance Provisions that accompany each of the adopted Revised Standards are adopted by the BCUC.

13. The Revised Standards and BC implementation plans adopted by the BCUC are to be posted by the Western Electricity Coordinating Council on its website with a link from the BCUC website.

14. Entities subject to MRS adopted in BC must report to the BCUC and may, on a voluntary basis, report to NERC and/or to FERC.

DATED at the City of Vancouver, in the Province of British Columbia, this 30th day of July 2025.

BY ORDER

Electronically signed by Elizabeth A. (Lisa) Brown

E. A. Brown
Commissioner

Attachments

British Columbia Utilities Commission
Reliability Standards with Effective Dates adopted in British Columbia

Standard	Name	BCUC Order	Effective Date / Notes
BAL-001-2	Real Power Balancing Control Performance	R-14-16	July 1, 2016
BAL-002-3	Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event	R-21-19	April 1, 2020
BAL-002-WECC-3	Contingency Reserve	R-34-22A1	October 29, 2022
BAL-003-2	Frequency Response and Frequency Bias Setting	R-21-21	October 1, 2021
BAL-004-WECC-3[1]	Automatic Time Error Correction	R-21-19	January 1, 2020
BAL-004-WECC-4	Automatic Time Error Correction	R-9-25A	October 1, 2025
BAL-005-1	Balancing Authority Control	R-33-18	October 1, 2019
CIP-002-5.1a	Cyber Security — BES Cyber System Categorization	R-33-18	October 1, 2018 and as per BC-specific Implementation Plan
CIP-003-8[1]	Cyber Security — Security Management Controls	R-19-20	October 1, 2020 and as per BC-specific Implementation Plan
CIP-003-9	Cyber Security — Security Management Controls	R-19-24	October 1, 2027 and as per BC-specific Implementation Plan
CIP-004-6[1]	Cyber Security — Personnel & Training	R-39-17	October 1, 2018 and as per BC-specific Implementation Plan
CIP-004-7	Cyber Security — Personnel & Training	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
CIP-005-7	Cyber Security – Electronic Security Perimeter(s)	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan

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

Standard	Name	BCUC Order	Effective Date / Notes
CIP-006-6	Cyber Security — Physical Security of BES Cyber Systems	R-39-17	October 1, 2018 and as per BC-specific Implementation Plan
CIP-007-6	Cyber Security — System Security Management	R-39-17	October 1, 2018 and as per BC-specific Implementation Plan
CIP-008-6	Cyber Security – Incident Reporting and Response Planning	R-19-20	April 1, 2023
CIP-009-6	Cyber Security — Recovery Plans for BES Cyber Systems	R-39-17	October 1, 2018 and as per BC-specific Implementation Plan
CIP-010-4	Cyber Security – Configuration Change Management and Vulnerability Assessments	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan
CIP-011-2[1]	Cyber Security – Information Protection	R-39-17	October 1, 2018 and as BC-specific Implementation Plan
CIP-011-3	Cyber Security – Information Protection	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
CIP-012-1[1]	Cyber Security – Communications between Control Centers	R-21-21	October 1, 2023
CIP-012-2	Cyber Security – Communications between Control Centers	R-9-25A	October 1, 2027
CIP-013-2	Cyber Security - Supply Chain Risk Management	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan
CIP-014-3	Physical Security	R-44-23	September 8, 2023
COM-001-3	Communications	R-39-17	R1, R2: October 1, 2017 R3-R13: October 1, 2018
COM-002-4	Operating Personnel Communications Protocols	R-32-16A	April 1, 2017
EOP-003-1[2]	Load Shedding Plans	G-67-09	November 1, 2010
EOP-004-4	Event Reporting	R-21-19	October 1, 2020

[2] Reliability standard is superseded by EOP-011-2 as of the effective date of EOP-011-2 and PRC-010-2 Requirement 1.

Standard	Name	BCUC Order	Effective Date / Notes
EOP-005-3	System Restoration from Blackstart Resources	R-21-19	October 1, 2020
EOP-006-3	System Restoration Coordination	R-21-19	October 1, 2020
EOP-008-2	Loss of Control Center Functionality	R-21-19	October 1, 2020
EOP-010-1	Geomagnetic Disturbance Operations	R-38-15	R1, R3: October 1, 2016 R2: October 1, 2017
EOP-011-2[1]	Emergency Preparedness and Operations	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan
EOP-011-4	Emergency Operations	R-9-25A	October 1, 2026 and as per BC implementation plan
EOP-012-2	Extreme Cold Weather Preparedness and Operations	R-9-25A	October 1, 2026 and as per BC implementation plan
FAC-001-3 (errata revision)[1]	Facility Interconnection Requirements	R-44-23	September 8, 2023
FAC-001-4	Facility Interconnection Requirements	R-6-25	October 1, 2026
FAC-002-3[1]	Facility Interconnection Studies	R-21-21	January 1, 2022
FAC-002-4	Facility Interconnection Studies	R-6-25	October 1, 2026
FAC-003-4[1]	Transmission Vegetation Management	R-39-17	October 1, 2017
FAC-003-5	Transmission Vegetation Management	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
FAC-008-5	Facility Ratings	R-34-22A1	April 1, 2023
FAC-010-3	System Operating Limits Methodology for the Planning Horizon	R-39-17	R1–R4: October 1, 2017 R1-R4: Retired October 1, 2025
FAC-011-3[1]	System Operating Limits Methodology for the Operations Horizon	R-39-17	October 1, 2017
FAC-011-4	System Operating Limits Methodology for the Operations Horizon	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan

Standard	Name	BCUC Order	Effective Date / Notes
FAC-014-2[1]	Establish and Communicate System Operating Limits	G-167-10	January 1, 2011
FAC-014-3	Establish and Communicate System Operating Limits	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
FAC-501-WECC-2[1]	Transmission Maintenance	R-21-19	October 1, 2019
FAC-501-WECC-4	Transmission Maintenance	R-9-25A	January 30, 2026
INT-006-5	Evaluation of Interchange Transactions	R-34-22A1	October 29, 2022
INT-009-3	Implementation of Interchange	R-34-22A1	October 29, 2022
IRO-001-4	Reliability Coordination – Responsibilities	R-39-17	October 1, 2017
IRO-002-7	Reliability Coordination – Monitoring and Analysis	R-34-22A1	October 29, 2022
IRO-006-5	Reliability Coordination – Transmission Loading Relief	R-1-13	April 15, 2013
IRO-006-WECC-3	Qualified Path Unscheduled Flow (USF) Relief	R-19-20	January 1, 2021
IRO-008-2[1]	Reliability Coordinator Operational Analyses and Real-time Assessments	R-39-17	October 1, 2017
IRO-008-3	Reliability Coordinator Operational Analyses and Real-time Assessments	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
IRO-009-2	Reliability Coordinator Actions to Operate Within IROLs	R-39-17	October 1, 2017
IRO-010-4[1]	Reliability Coordinator Data Specification and Collection	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan
IRO-010-5	Reliability Coordinator Data Specification and Collection	R-19-24	April 1, 2026
IRO-014-3	Coordination Among Reliability Coordinators	R-39-17	October 1, 2017
IRO-017-1	Outage Coordination	R-39-17	October 1, 2020

Standard	Name	BCUC Order	Effective Date / Notes
IRO-018-1(i)	Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities	R-33-18	April 1, 2020
MOD-010-0[3]	Steady-State Data for Modeling and Simulation for the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-012-0[3]	Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-025-2	Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	R-38-15 With revised effective dates by Order R-14-20	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by April 1, 2021
MOD-026-1	Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions	R-38-15	R1: October 1, 2016 R2: 30% by October 1, 2019 50% by October 1, 2021 100% by October 1, 2025 R3-R6: October 1, 2015
MOD-027-1	Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	R-38-15	R1: October 1, 2016 R2: 30% by October 1, 2019 50% by October 1, 2021 100% by October 1, 2025 R3-R5: October 1, 2015
MOD-031-3	Demand and Energy Data	R-21-21	January 1, 2022
MOD-032-1	Data for Power System Modeling and Analysis	R-6-25	R1: October 1, 2026 R2-R4: July 1, 2027
MOD-033-2	Steady-State and Dynamic System Model Validation	R-6-25	July 1, 2028
NUC-001-4	Nuclear Plant Interface Coordination	R-21-21	October 1, 2021

[3] Reliability standard will be superseded by Requirement 2 of MOD-032-1 by the effective date of MOD-032-1 Requirement 2.

Standard	Name	BCUC Order	Effective Date / Notes
PER-003-2	Operating Personnel Credentials	R-21-19	April 1, 2020
PER-005-2	Operations Personnel Training	R-38-15	R1-R4, R6: October 1, 2016 R5: October 1, 2017
PER-006-1	Specific Training for Personnel	R-21-19	October 1, 2021
PRC-002-2[1]	Disturbance Monitoring and Reporting Requirements	R-32-16A	R1, R5: April 1, 2017 R2-R4, R6-R11: staged as per BC-specific Implementation Plan R12: July 1, 2017
PRC-002-4	Disturbance Monitoring and Reporting Requirements	R-19-24	October 1, 2025
PRC-004-6	Protection System Misoperation Identification and Correction	R-34-22A1	April 1, 2023
PRC-005-1.1b[1, 4]	Transmission and Generation Protection System Maintenance and Testing	R-32-14	January 1, 2015
PRC-005-6	Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance	R-39-17	R1, R2, R5: October 1, 2019 R3, R4: See BC-specific Implementation Plan
PRC-006-5	Automatic Underfrequency Load Shedding	R-6-25	July 1, 2027
PRC-007-0[5]	Assuring Consistency of Entity Underfrequency Load Shedding Program Requirements	G-67-09	November 1, 2010
PRC-008-0[4]	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	G-67-09	November 1, 2010

[4] Reliability standard is superseded by PRC-005-6 as per the PRC-005-6 B.C. specific Implementation Plan.

[5] Reliability standard is superseded by PRC-006-5.

Standard	Name	BCUC Order	Effective Date / Notes
PRC-009-0[5]	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	G-67-09	November 1, 2010
PRC-010-0[1]	Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	G-67-09	November 1, 2010 R2: Retired January 21, 2014[6]
PRC-010-2	Under Voltage Load Shedding	R-6-25	December 1, 2025
PRC-011-0[4]	Undervoltage Load Shedding System Maintenance and Testing	G-67-09	November 1, 2010
PRC-012-2	Remedial Action Schemes	R-33-18	October 1, 2021, except for R1 Attachment 1, Section II Parts 6(d) and 6(e); R2 Attachment 2, Section I Parts 7(d) and 7(e); and R4: Adoption held in abeyance
		R-6-25	R1 Attachment 1, Section II Parts 6(d) and 6(e); R2 Attachment 2, Section I Parts 7(d) and 7(e); and R4: July 1, 2028
PRC-017-1[4]	Remedial Action Scheme Maintenance and Testing	R-39-17	October 1, 2017
PRC-019-2	Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	R-32-16A With revised effective dates by Order R-14-20	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by April 1, 2021

[6] On November 21, 2013, FERC Order 788 (referred to as Paragraph 81) approved the retiring of the reliability standard requirements.

Standard	Name	BCUC Order	Effective Date / Notes
PRC-021-1[7]	Under Voltage Load Shedding Program Data	G-67-09	November 1, 2010
PRC-022-1[7]	Under Voltage Load Shedding Program Performance	G-67-09	November 1, 2010 R2: Retired January 21, 2014[6]
PRC-023-2[1, 8]	Transmission Relay Loadability	R-41-13	R1-R5: For circuits identified by sections 4.2.1.1 and 4.2.1.4 that meet Criterion 6 of Requirement 1: 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 that meet Criterion 6 of Requirement 1; and R6: Adoption held in abeyance
		R-6-25	For circuits identified by sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement 1: October 1, 2025
PRC-023-4[1]	Transmission Relay Loadability	R-39-17	R1-R5 Circuits 4.2.1.1, 4.2.1.4: October 1, 2017 with the exception of Criterion 6 of R1 which will not become effective until PRC-025-2 R1 is completely effective in BC. Until then, PRC-023-2 R1, Criterion 6 will remain in effect R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: Adoption held in abeyance at this time

[7] Reliability standard is superseded by PRC-010-2.

[8] PRC-023-2 Requirement 1, Criterion 6 only is superseded by PRC-025-2 as of PRC-025-2's 100 per cent Effective Date.

Standard	Name	BCUC Order	Effective Date / Notes
PRC-023-5[1]	Transmission Relay Loadability	R-44-23	R1-R5 Circuits 4.2.1.1 and 4.2.1.4: October 1, 2025 except R1 criterion 6 which will not become effective until PRC-025-2 is completely effective in BC. Until then, PRC-023-2 R1 Criterion 6 remains in effect. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: Adoption held in abeyance at this time
PRC-023-6	Transmission Relay Loadability	R-6-25	October 1, 2025
PRC-024-3	Frequency and Voltage Protection Settings for Generating Resources	R-21-21	October 1, 2023
PRC-025-2	Generator Relay Loadability	R-21-19	October 1, 2019 and staged per BC-specific Implementation Plan
PRC-026-2	Relay Performance During Stable Power Swings	R-6-25	R1: January 1, 2029 R2-R4: January 1, 2031
PRC-027-1	Coordination of Protection Systems for Performance During Faults	R-21-19	October 1, 2021
TOP-001-5[1]	Transmission Operations	R-34-22A1	October 29, 2022
TOP-001-6	Transmission Operations	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
TOP-002-4[1]	Operations Planning	R-39-17 With revised effective dates by Order R-14-20	April 1, 2021
TOP-002-5	Operations Planning	R-9-25A	April 1, 2027
TOP-003-5[1]	Operational Reliability Data	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan
TOP-003-6.1	Transmission Operator and Balancing Authority Data and Information Specification and Collection	R-19-24	April 1, 2026

Standard	Name	BCUC Order	Effective Date / Notes
TOP-010-1(i)	Real-time Reliability Monitoring and Analysis Capabilities	R-33-18 With revised effective dates by Order R-14-20	April 1, 2021
TPL-001-4[1]	Transmission System Planning Performance Requirements	R-27-18A	R1: July 1, 2019 R2-R6, R8: July 1, 2020 R7: Adoption held in abeyance
TPL-001-5.1	Transmission System Planning Performance Requirements	R-6-25	July 1, 2030
TPL-007-4	Transmission System Planned Performance for Geomagnetic Disturbance Events	R-6-25	April 1, 2026
VAR-001-5	Voltage and Reactive Control	R-21-19	October 1, 2019
VAR-002-4.1	Generator Operation for Maintaining Network Voltage Schedules	R-33-18	October 1, 2018
VAR-501-WECC-3.1[1]	Power System Stabilizer (PSS)	R-33-18	October 1, 2020 R3: For units placed into service after the effective date: January 1, 2021 For units placed into service prior to the effective date: January 1, 2024
VAR-501-WECC-4	Power System Stabilizer (PSS)	R-9-25A	October 1, 2025

British Columbia (B.C.) Exceptions to the Glossary of Terms Used in North American Electric Reliability Corporation (NERC) Reliability Standards (NERC Glossary)

Updated by Order R-9-25A.

Introduction:

This document is to be used in conjunction with the NERC Glossary dated November 4, 2024.

- The NERC Glossary terms listed in Table 1 below are effective in B.C. on the date specified in the "Effective Date" column.
- Table 2 below outlines the adoption history by the BCUC of the NERC Glossaries in B.C.
- Any NERC Glossary terms and definitions in the NERC Glossary that are not approved by FERC on or before November 30, 2024 are of no force or effect in B.C.
- Any NERC Glossary terms that have been remanded or retired by NERC are of no force or effect in B.C., with the exception of those remanded or retired NERC Glossary terms which have not yet been retired in B.C.
- The Texas Regional Entity, Northeast Power Coordinating Council and Reliability First regional definitions listed at the end of the NERC Glossary have been adopted by the NERC Board of Trustees for use in regional standards and are of no force or effect in B.C.

Table 1: B.C. Effective Date Exceptions to Definitions in the November 4, 2024 Version of the NERC Glossary

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
ACE Diversity Interchange	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Actual Frequency (FA)	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Actual Net Interchange (NI_A)[1]	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Actual Net Interchange	NI_A	Report No. 18	R-9-25A	Adoption	July 31, 2025
Adjacent Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Alternative Interpersonal Communication	-	Report No. 9	R-32-16A	Adoption	October 1, 2017
Area Control Error[1] (from NERC section of the Glossary)	ACE	Report No. 7	R-32-14	Adoption	October 1, 2014
Area Control Error (from NERC section of the Glossary)	ACE	Report No. 18	R-9-25A	Adoption	April 1, 2026
Area Control Error (from the WECC Regional Definitions section of the Glossary)	ACE	Report No. 7	R-32-14	Retirement	October 1, 2014
Arranged Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Attaining Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Automatic Generation Control[1]	AGC	Report No. 11	R-33-18	Adoption	October 1, 2019
Automatic Generation Control	AGC	Report No. 18	R-9-25A	Adoption	July 31, 2025
Automatic Time Error Correction	-	Report No. 7	R-32-14	Adoption	October 1, 2014

[1] NERC Glossary term definition is superseded by the revised NERC Glossary term definition listed immediately below it as of the effective date(s) of the revised NERC Glossary term definition.

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Automatic Time Error Correction (I_{ATEC})[1]	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Automatic Time Error Correction	ATEC	Report No. 18	R-9-25A	Adoption	July 31, 2025
Balancing Authority	-	Report No. 11	R-33-18	Adoption	January 1, 2019
Balancing Authority Area	BAA	Report No. 18	R-9-25A	Adoption	July 31, 2025
Balancing Contingency Event[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Balancing Contingency Event	BCE	Report No. 18	R-9-25A	Adoption	July 31, 2025
BES Cyber Asset[1]	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
BES Cyber Asset	BCA	Report No. 10	R-39-17	Adoption	October 1, 2018
BES Cyber System	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
BES Cyber System Information	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Blackstart Capability Plan	-	Report No. 7	R-32-14	Retirement	August 1, 2015
Blackstart Resource[1]	-	Report No. 6	R-41-13	Adoption	December 12, 2013
Blackstart Resource	-	Report No. 10	R-39-17	Adoption	October 1, 2017

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Bulk Electric System	BES	Report No. 8	R-38-15	-	October 1, 2015
Bulk-Power System[1]	-	Report No. 8	R-38-15	-	October 1, 2015
Bulk-Power System	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Bus-tie Breaker	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Cascading	-	Report No. 10	R-39-17	Adoption	October 1, 2017
CIP Exceptional Circumstance	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
CIP Senior Manager	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Composite Confirmed Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Confirmed Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Composite Protection System	-	Report No. 9	R-32-16A	Adoption	October 1, 2017
Consequential Load Loss	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Contingency Event Recovery Period	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Contingency Reserve	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Contingency Reserve Restoration Period	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Contributing Schedule (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Control Center	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Control Performance Standard	CPS	Report No. 18	R-9-25A	Adoption	April 1, 2026
Critical Assets	-	Report No. 9	R-32-16A	Retirement	September 30, 2018
Critical Cyber Assets	-	Report No. 9	R-32-16A	Retirement	September 30, 2018
Cyber Assets	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Cyber Security Incident[1]	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Cyber Security Incident	-	Report No. 13	R-19-20	Adoption	April 1, 2023
Demand-Side Management	DSM	Report No. 9	R-32-16A	Adoption	October 1, 2016
Dial-up Connectivity	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Distribution Provider	DP	Report No. 10	R-39-17	Adoption	October 1, 2017
Disturbance[1]	-	Report No. 11	R-33-18	Retirement	October 1, 2018

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Disturbance	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Disturbance Control Standard	DCS	Report No. 18	R-9-25A	Retirement	July 31, 2025
Dynamic Interchange Schedule or Dynamic Schedule[1]	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Dynamic Interchange Schedule or Dynamic Schedule	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Electronic Access Control or Monitoring Systems	EACMS	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Electronic Access Point	EAP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Electronic Security Perimeter	ESP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Element	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Energy Emergency	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Energy Emergency	-	Report No. 11	R-33-18	Retirement	October 1, 2018
External Routable Connectivity	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5,

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
					CIP-010-1, and CIP-011-1) where this term is referenced.
Extreme Cold Weather Temperature	-	Report No. 18	R-9-25A	Adoption	October 1, 2026
Fixed Fuel Supply Component	-	Report No. 18	R-9-25A	Adoption	October 1, 2026
Frequency Bias Setting[1]	-	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Frequency Bias Setting	FBS	Report No. 18	R-9-25A	Adoption	July 31, 2025
Frequency Error	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Frequency Response Measure	FRM	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Frequency Response Obligation	FRO	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Frequency Response Sharing Group	FRSG	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Generator Cold Weather Constraint	-	Report No. 18	R-9-25A	Adoption	October 1, 2026
Generator Cold Weather Critical Component	-	Report No. 18	R-9-25A	Adoption	October 1, 2026
Generator Cold Weather Reliability Event	-	Report No. 18	R-9-25A	Adoption	October 1, 2026
Generator Operator	GOP	Report No. 10	R-39-17	Adoption	October 1, 2017
Generator Owner	GO	Report No. 10	R-39-17	Adoption	October 1, 2017
Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment	GMD	PC Report 2025	R-6-25	Adoption	April 1, 2026

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Implemented Interchange	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Inadvertent Interchange	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Inadvertent Interchange Management	I_{IM}	Report No. 18	R-9-25A	Adoption	July 31, 2025
Interactive Remote Access	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Interchange Authority	IA	Report No. 10	R-39-17	Adoption	October 1, 2017
Interchange Meter Error (IME)[1]	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Interchange Meter Error	I_{ME}	Report No. 18	R-9-25A	Adoption	July 31, 2025
Interconnected Operations Service	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Interconnection	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Interconnection Reliability Operating Limit	IROL	Report No. 6	R-41-13	Adoption	December 12, 2013
Intermediate Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Intermediate System	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Interpersonal Communication	-	Report No. 9	R-32-16A	Adoption	October 1, 2017
Load-Serving Entity	LSE	Report No. 10	R-39-17	Adoption	October 1, 2017

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Long-Term Transmission Planning Horizon	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Minimum Vegetation Clearance Distance	MVCD	Report No. 7	R-32-14	Adoption	August 1, 2015
Misoperation	-	Report No. 9	R-32-16A	Adoption	October 1, 2017
Most Severe Single Contingency	MSSC	Report No. 10	R-39-17	Adoption	January 1, 2018
Native Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Net Interchange Schedule	-	Report No. 18	R-9-25A	Retirement	July 31, 2025
Net Scheduled Interchange	-	Report No. 18	R-9-25A	Retirement	July 31, 2025
Non-Consequential Load Loss	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Non-Spinning Reserve	-	Report No. 11	R-33-18	Retirement	October 1, 2018
Operating Instruction	-	Report No. 9	R-32-16A	Adoption	April 1, 2017
Operating Reserve – Spinning		Report No. 18	R-9-25A	Adoption	July 31, 2025
Operating Reserve – Supplemental		Report No. 18	R-9-25A	Adoption	July 31, 2025
Operational Planning Analysis[1]	-	Report No. 6	R-41-13	Adoption	December 12, 2013
Operational Planning Analysis[1]	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Operational Planning Analysis[1]	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Operational Planning Analysis	OPA	Report No. 12	R-21-19	Adoption	October 1, 2021
Operations Support Personnel	-	Report No. 8	R-38-15	Adoption	Align with effective date of Requirement 5 of the PER-005-2 standard where this term is referenced
Overlap Regulation Service	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Physical Access Control Systems	PACS	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5,

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
					CIP-010-1, and CIP-011-1) where this term is referenced.
Physical Security Perimeter	PSP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Planning Assessment	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Planning Authority	PA	Report No. 10	R-39-17	Adoption	October 1, 2017
Point of Receipt	POR	Report No. 10	R-39-17	Adoption	October 1, 2017
Pre-Reporting Contingency Event ACE Value	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Protected Cyber Assets[1]	PCA	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Protected Cyber Assets	PCA	Report No. 10	R-39-17	Adoption	October 1, 2018
Protection System	-	Report No. 6	R-41-13	Adoption	January 1, 2015 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 Coordination Study	-	Report No. 12	R-21-19	Adoption	October 1, 2021

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Protection System Maintenance Program	PSMP	Report No. 8	R-38-15	Adoption	Align with effective date of Requirement 1 of the PRC-005-2 standard where this term is referenced
Protection System Maintenance Program (PRC-005-6)	PSMP	Report No. 10	R-39-17	Adoption	October 1, 2019
Pseudo-Tie[1]	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Pseudo-Tie[1]	-	Report No. 11	R-33-18	Adoption	January 1, 2019
Pseudo-Tie	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Qualified Controllable Device (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Qualified Path (WECC Regional Term)	-	Report No. 13	R-19-20	Adoption	January 1, 2021
Qualified Transfer Path (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Qualified Transfer Path Curtailment Event (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Ramp Rate or Ramp	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Reactive Power	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Real Power	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Real-time Assessment[1]	-	Report No. 6	R-41-13	Adoption	January 1, 2014
Real-time Assessment[1]	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Real-time Assessment	RTA	Report No. 12	R-21-19	Adoption	October 1, 2021
Regulation Service	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Reliability Adjustment Arranged Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Reliability Coordinator	RC	Report No. 10	R-39-17	Adoption	October 1, 2017
Reliability Directive	-	Report No. 9	R-32-16A	Retirement	July 18, 2016
Reliability Standard[1]	-	Report No. 8	R-32-14	Adoption	October 1, 2015
Reliability Standard	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Reliable Operation[1]	-	Report No. 8	R-32-14	Adoption	October 1, 2015
Reliable Operation	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Relief Requirement (WECC Regional Term)	-	Report No. 8	R-38-15	Adoption	Align with effective date of IRO-006-WECC-2 standard where this term is referenced
Relief Requirement (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Remedial Action Scheme[1]	RAS	Report No. 1	G-67-09	Adoption	June 4, 2009
Remedial Action Scheme	RAS	PC Report 2025	R-6-25	Adoption	December 1, 2025
Removable Media[1]	-	Report No. 10	R-39-17	Adoption	October 1, 2018
Removable Media	-	Report No. 12	R-21-19	Adoption	October 1, 2019
Reporting ACE[1]	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Reporting Area Control Error	Reporting ACE	Report No. 18	R-9-25A	Adoption	July 31, 2025
Reportable Balancing Contingency Event[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Reportable Balancing Contingency Event	RBCE	Report No. 18	R-9-25A	Adoption	July 31, 2025
Reportable Cyber Security Incident[1]	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5,

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
					CIP-010-1, and CIP-011-1) where this term is referenced.
Reportable Cyber Security Incident	-	Report No. 13	R-19-20	Adoption	April 1, 2023
Reportable Disturbance	-	Report No. 18	R-9-25A	Retirement	July 31, 2025
Request for Interchange	RFI	Report No. 8	R-38-15	Adoption	October 1, 2015
Reserve Sharing Group[1]	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Reserve Sharing Group	RSG	Report No. 18	R-9-25A	Adoption	July 31, 2025
Reserve Sharing Group Reporting ACE[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Reserve Sharing Group Reporting ACE	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Resource Planner	RP	Report No. 10	R-39-17	Adoption	October 1, 2017
Scheduled Frequency	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
Scheduled Net Interchange (NI_S)[1]	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Scheduled Net Interchange	NI_S	Report No. 18	R-9-25A	Adoption	July 31, 2025
Sink Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Source Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Special Protection System (Remedial Action Scheme)[1]	SPS	Report No. 1	G-67-09	Adoption	June 4, 2009
Special Protection System (Remedial Action Scheme)	SPS	PC Report 2025	R-6-25	Adoption	December 1, 2025
Spinning Reserve	-	Report No. 11	R-33-18	Retirement	October 1, 2018
Supplemental Regulation Service	-	Report No. 18	R-9-25A	Adoption	July 31, 2025
System Operating Limit[1]	SOL	Report No. 10	R-39-17	Adoption	October 1, 2017

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
System Operating Limit	-	Report No. 16	R-44-23	Adoption	October 1, 2025
System Operator	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) as reference is made to the term Control Center as part of the definition of System Operator. The term Control Center is in turn referenced from the CIP Version 5 standards.
System Voltage Limit	-	Report No. 16	R-44-23	Adoption	October 1, 2025
Tie Line Bias	TLB	Report No. 18	R-9-25A	Adoption	July 31, 2025
Time Error	TE	Report No. 18	R-9-25A	Adoption	July 31, 2025
Time Error Correction	TEC	Report No. 18	R-9-25A	Adoption	July 31, 2025
Total Internal Demand	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Transient Cyber Asset[1]	-	Report No. 10	R-39-17	Adoption	October 1, 2018
Transient Cyber Asset	TCA	Report No. 12	R-21-19	Adoption	October 1, 2019
Transmission Customer	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Transfer Distribution Factor (WECC Regional Term)	TDF	Report No. 13	R-19-20	Retirement	December 31, 2020
Transmission Operator	TOP	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Owner	TO	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Planner	TP	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Service Provider	TSP	Report No. 10	R-39-17	Adoption	October 1, 2017
Under Voltage Load Shedding Program	UVLS Program	PC Report 2025	R-6-25	Adoption	December 1, 2025

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Right-of-Way	ROW	Report No. 7	R-32-14	Adoption	August 1, 2015
TLR (Transmission Loading Relief) Log	-	Report No. 7	R-32-14	Adoption	August 1, 2014
Vegetation Inspection	-	Report No. 7	R-32-14	Adoption	August 1, 2015

Table 2: NERC Glossary Adoption History in BC

NERC Glossary of Terms Version Date	Assessment Report Number	BCUC Order Adoption Date	BCUC Order Adopting	Effective Date
February 12, 2008	Report No. 1	June 4, 2009	G-67-09	1. The NERC Glossaries listed became effective as of the date of the respective BCUC Orders adopting them. 2. Specific effective dates of new and revised NERC Glossary terms adopted in a BCUC Order appear in attachments to the Order. Each Glossary term to be superseded by a revised Glossary term adopted in the Order shall remain in effect until the effective date of the Glossary term superseding it. 3. NERC Glossary terms which have not been approved by FERC are of no force or effect in B.C. 4. Any NERC Glossary terms that have been remanded or retired by NERC are of no force or effect in B.C., with the exception of those remanded or retired NERC Glossary terms which have not yet been retired in B.C. 5. The Electric Reliability Council of Texas, Northeast Power Coordinating Council and Reliability First regional definitions listed at the end of the NERC Glossary of Terms are of no force or effect in B.C.
April 20, 2010	Report No. 2	November 10, 2010	G-167-10	
August 4, 2011	Report No. 3	September 1, 2011	G-162-11 replacing G-151-11	
December 13, 2011	Report No. 5	January 15, 2013	R-1-13	
December 5, 2012	Report No. 6	December 12, 2013	R-41-13	
January 2, 2014	Report No. 7	July 17, 2014	R-32-14	
October 1, 2014	Report No. 8	July 24, 2015	R-38-15	
December 7, 2015	BAL-001-2	April 21, 2016	R-14-16	
December 7, 2015	Report No. 9	July 18, 2016	R-32-16A	
November 28, 2016	Report No. 10	July 26, 2017	R-39-17	
November 28, 2016	TPL-001-4	June 28, 2018	R-27-18A	
October 6, 2017	Report No. 11	October 1, 2018	R-33-18	
July 3, 2018	Report No.12	September 26, 2019	R-21-19	
August 12, 2019	Report No. 13	September 8, 2020	R-19-20	
October 8, 2020	Report No. 14	September 21, 2021	R-21-21	
June 28, 2021	Report No. 15	October 28, 2022	R-34-22A1	
March 29, 2022	Report No. 16	September 8, 2023	R-44-23	
March 8, 2023	Report No. 17	July 16, 2024	R-19-24	
November 4, 2024	Report No. 18	July 30, 2025	R-9-25A	

British Columbia Utilities Commission (BCUC)

BC Implementation Plan for Reliability Standard EOP-011-4

Applicable Standards

- EOP-011-4 Emergency Operations

Requested Retirements

- EOP-011-2

Prerequisite Standards

- None

Associated Definitions

- None

Applicable Entities

See subject Reliability Standard.

General Considerations

For Reliability Standard EOP-011-4, this implementation plan reflects consideration of the interaction that will be required between applicable entities and natural gas entities, as well as the fact that several entities (Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner) will have obligations under this standard for the first time under Requirement R8.

The implementation timeframe is not intended to extend the timeframe for an entity's existing responsibilities regarding load shedding under EOP-011-2; rather, the additional timeframe is intended to provide additional time to come into compliance with new and revised requirements specific to EOP-011-4.

Effective Date and Phased-In Compliance Dates

The effective dates for the Reliability Standard are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard EOP-011-4

The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the BCUC order adopting the standard.

Compliance Date for EOP-011-4 – Requirement R1 Part 1.2.5

Entities shall not be required to comply with the new and revised provisions (i.e., specific to UVLS, UFLS and critical natural gas infrastructure loads) in Requirement R1 Part 1.2.5 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R2 Part 2.2.8 and Part 2.2.9

Entities shall not be required to comply with the new and revised provisions (i.e., specific to UVLS, UFLS and critical natural gas infrastructure loads) in Requirement R2 Part 2.2.8 and Part 2.2.9 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R8

Entities shall not be required to comply with Requirement R8 until the later of: (1) 30 calendar months following notification by a Transmission Operator under EOP-011-4 Requirement R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area; or (2) 30 months after the effective date of Reliability Standard EOP-011-4.

Retirement Date

Reliability Standard EOP-011-2 shall be retired immediately prior to the effective date of Reliability Standard EOP-011-4 in British Columbia.

Time Period to Address New Designations under EOP-011-4 Requirements R7, R8

Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

British Columbia Utilities Commission (BCUC)

BC Implementation Plan for Reliability Standard EOP-012-2

Applicable Standards

- EOP-012-2 Extreme Cold Weather Preparedness and Operations

Prerequisite Standards

- None

Associated Definitions

- Generator Cold Weather Critical Component
- Fixed Fuel Supply Component
- Generator Cold Weather Reliability Event
- Generator Cold Weather Constraint(s)
- Extreme Cold Weather Temperature

Applicable Entities

- Generator Owner
- Generator Operator

Effective Date and Phased-In Compliance Dates

The effective dates for the Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Standard EOP-012-2 and Definitions

The EOP-012-2 standard and associated definitions shall become effective on the same date as EOP-011-4 becomes effective in British Columbia.

Compliance Date for EOP-012-2 - Requirement R3

Entities shall not be required to comply with Requirement R3 until twelve (12) months after the effective date of Reliability Standard EOP-012-2.

Initial Performance of Periodic Requirements

Entities shall be compliant with Requirement R1 by the effective date. Entities shall perform their first periodic review under Requirement R1 by no more than 60 months after the effective date of EOP- 012-2.

A. Introduction

1. **Title:** Automatic Time Error Correction

2. **Number:** BAL-004-WECC-4

3. **Purpose:** To maintain Western Interconnection (WI) frequency, and ensure that time error accumulation via Primary Inadvertent Interchange (PII) payback is conducted in a manner that does not result in a negative impact on reliability.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authorities operating synchronously within the WI

5. **Effective Date*:**

6. **Background:**

Pre-2000 (prior to mandatory Standards), the Western Electricity Coordinating Council (WECC) operated using the Minimum Operating Reliability Criteria (MORC). Per MORC Section D. Time Control, Control Areas were required to assist in maintaining frequency at or near 60.0 Hz, as prescribed in the Western System Coordinating Council (WSCC)[1] Procedure for Time Error Control (PTEC). Various versions of the PTEC predate 1980. In February 2003, the WECC Automatic Time Error Correction (ATEC) Procedure (Procedure) became effective for all Balancing Authorities in the WI. The original intent of the Procedure was to minimize the number of manual Time Error Corrections in the WI.[2]

In June 2007, the Procedure was translated into BAL-STD-004-1, Time Error Correction, followed by BAL-004-WECC-1 through 3, Time Error Correction.[3] BAL-004-WECC-1 required Balancing Authorities within the WI to maintain Interconnection frequency within a predefined frequency profile, and to ensure that Time Error Corrections would not result in a negative impact on Interconnection reliability.

In September 2009, in response to Federal Energy Regulatory Commission (FERC) Order 723, WECC received Standard Authorization Request (SAR) WECC-0068 requesting modification of BAL-004-WECC-1. Modifications were effective April 1, 2014, creating BAL-004-WECC-2. BAL-004-WECC-2 introduced two performance metrics: 1) in Requirement R1, a 150% metric, and 2) in Requirement R2, a 90-day metric. Neither of these metrics are supported by technical studies. They were included in BAL-004-WECC-

[1] WECC began in 1967 as the Western Systems Coordinating Council (WSCC), a group of 40 power systems with a common goal of providing reliable power to the public whom they served. WECC was founded March 22, 1994.

[2] The Procedure provided for cost assignment and equitable payback of Inadvertent Interchange, not otherwise addressed in BAL-004-4, Time Error Correction.

[3] See Version History Table.

*** Mandatory BC Effective Date: October 1, 2025**

2 as a compromise during drafting.

In May 2018, FERC approved minor revisions to BAL-004-WECC-2 as part of WECC SAR WECC-0124, effective October 1, 2018, creating BAL-004-WECC-3.[4]

In 2023, this Standard was reviewed as part of the WECC SAR WECC-0147. The drafting team noted: 1) Version 3, Requirement R5 migrated from the pre-2000 MORC without initial or subsequent technical support, and 2) R5 addresses capabilities of Automatic Generator Control (AGC) found in no other Standard, without mandating its use or stating how that capability interfaces with ATEC. R5 is retained herein until it can be properly addressed per a NERC Standard Authorization Request.

7. Standard-Only Definition:

7.1 Interchange Software:

This Standard uses the Standard-Only term "Interchange Software" to mean:

The single electronic confirmation tool identified by the Western Electricity Coordinating Council (WECC), or its successor, to be used by all Balancing Authorities throughout the Western Interconnection (WI), that serves as the primary means for confirmation and creation of the final record of Scheduled Net Interchange (NI_S[5]) and Actual Net Interchange (NI_A[6]), during all periods when the Interchange Software is available.

7.2. ATEC:

This Standard uses the term "ATEC" as defined in the WECC Regional Definitions section of the NERC Glossary of Terms Used in Reliability Standards.

[4] FERC Docket No. RD18-2-000. Effective Date October 1, 2018.
[5] Previously called Net Scheduled Interchange
[6] Previously called Net Actual Interchange

B. Requirements and Measures

R1. Each Balancing Authority shall use the Interchange Software as the sole source of data to calculate its ATEC. [Violation Risk Factor: Severe] [Time Horizon: Operations Assessment]

M1. Each Balancing Authority will have evidence that it used the Interchange Software as the sole source of data to calculate its ATEC, as required in Requirement R1.

Evidence may include, but is not limited to production of a corporate attestation or operating procedure indicating use of the Interchange Software as the sole source for calculating ATEC.

R2. Each Balancing Authority shall operate its system such that, the month-end absolute value of its On-Peak and Off-Peak, accumulated Primary Inadvertent Interchange (PIIaccum), as calculated by the Interchange Software, are each individually less than or equal to 150% of the previous calendar year's integrated hourly peak demand where peak demand is total load plus total exports. *[Violation Risk Factor Medium:] [Time Horizon: Operations Assessment]*

2.1. For new Balancing Authorities, the peak demand will be the maximum hourly integrated peak demand as it increases during the first year of operation.

M2. Each Balancing Authority will have evidence that it operated its system such that the month-end absolute value of its On-Peak and Off-Peak, accumulated Primary Inadvertent Interchange (PIIaccum), as calculated by the Interchange Software, are each individually less than or equal to 150% of the previous calendar year's integrated hourly peak demand where peak demand is total load plus total exports, average load in those hours, as calculated by the Interchange Software, per Requirement R2, or per the exception allowed in R2.1.

R3. Each Balancing Authority shall, upon discovery of an error in its On-Peak or Off-Peak Inadvertent Interchange calculation, recalculate and correct the Inadvertent Interchange values within 90 days from the time the error is discovered. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M3. Each Balancing Authority discovering an error in its On-Peak or Off-Peak Inadvertent Interchange calculation will have evidence that it recalculated and corrected the Inadvertent Interchange values, within 90 days from the time the error is discovered, as required in Requirement R3.

Evidence may include, but is not limited to:

- Screen shots from the Interchange Software;
- Screen shots from the Balancing Authority's internal software functions such as internal databases, spreadsheets, and displays;
- Dated archive files; and
- Historic data.

R4. Each Balancing Authority shall keep ATEC in service, with an allowable exception period of less than or equal to an accumulated 24 hours per calendar quarter for

ATEC to be out of service. This period is separate from any period during which the Interchange Software was unavailable. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M4. Each Balancing Authority will have evidence that it kept ATEC in service as required in Requirement R4, subject to the allowable exceptions provided.

Evidence may include, but is not limited to:

- Screen shots from the Interchange Software;
- Screen shots from the Balancing Authority's internal software functions such as internal databases, spreadsheets, and displays;
- Dated archive files; and
- Historical data.

R5. Each Balancing Authority shall be able to change its Automatic Generation Control (AGC) operating mode to correspond to current operating conditions. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M5. Each Balancing Authority will have evidence that its AGC is able to change operating modes to correspond to current operating conditions, as required in R5.

Evidence may include, but is not limited to:

- Screen shots from Energy Management System; and
- Demonstration using an off-line system.

R6. Each Balancing Authority shall upload hourly Actual Net Interchange (NI_A) to the Interchange Software no later than 50 minutes after each hour. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M6. Each Balancing Authority will have evidence that it uploaded hourly Actual Net Interchange (NI_A) to the Interchange Software no later than 50 minutes after each hour, as required in Requirement R6.

Evidence may include, but is not limited to:

- Screen shots from the Interchange Software;
- Screen shots from the Balancing Authority's internal software functions such as internal databases, spreadsheets, and displays;
- Dated archive files; and
- Historical data.

R7. Each Balancing Authority making a month-end adjustment shall input that value as part of its Actual Net Interchange (NI_A). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M7. Each Balancing Authority making a month-end adjustment will have evidence that it input that value as part of its Actual Net Interchange (NI_A), as required in Requirement R7.

R8. Each Balancing Authority making a month-end adjustment shall ensure that value is added to its accumulated Primary Inadvertent Interchange. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M8. Each Balancing Authority making a month-end adjustment will have evidence that the value was added to its accumulated Primary Inadvertent Interchange, as required in Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:
The British Columbia Utilities Commission.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity 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.

- Each Balancing Authority in the WI shall keep the following records for the preceding calendar year (January – December) plus the current calendar year:
  - Its values for PIIhourly, PIIaccum (On-Peak and Off-Peak), ΔTE, and any month-end adjustments.
  - Documentation illustrating any period(s) during which the Balancing Authority operated without ATEC, including the reason ATEC was not in operation.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	NA	NA	NA	The Balancing Authority failed to use the Interchange Software as the sole source to calculate ATEC.
R2.	Following the conclusion of each month each Balancing Authority's absolute value of PIIaccum for either the On-Peak period or Off-Peak period exceeded 150%, but was less than or equal to 160% of the previous calendar year's peak demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PIIaccum for either the On-Peak period or Off-Peak period exceeded 160%, but was less than or equal to 170% of the previous calendar year's peak demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PIIaccum for either the On-Peak period or Off-Peak period exceeded 170%, but was less than or equal to 180% of the previous calendar year's peak demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PIIaccum for either the On-Peak period or Off-Peak period exceeded 180% of the previous calendar year's peak demand or peak generation for generation-only Balancing Authorities.
R3.	The Balancing Authority did not recalculate PIIhourly and adjust the PIIaccum within 90 days of the discovery of the error; but made the required recalculations and adjustments within 120 days.	The Balancing Authority did not recalculate PIIhourly and adjust the PIIaccum within 120 days of the discovery of the error; but made the required recalculations and adjustments within 150 days.	The Balancing Authority did not recalculate PIIhourly and adjust the PIIaccum within 150 days of the discovery of the error; but made the required recalculations and adjustments within 180 days.	The Balancing Authority did not recalculate PIIhourly and adjust PIIaccum within 180 days of the discovery of the error.
R4.	The Balancing Authority operated during a calendar	The Balancing Authority operated during a calendar	The Balancing Authority operated during a calendar	The Balancing Authority operated during a calendar

	quarter without ATEC in service for more than an accumulated 24 hours, but less than or equal to 72 hours.	quarter without ATEC in service for more than an accumulated 72 hours, but less than or equal to 120 hours.	quarter without ATEC in service for more than an accumulated 120 hours, but less than or equal to 168 hours.	quarter without ATEC in service for more than an accumulated 168 hours.
R5.	N/A	N/A	N/A	The Balancing Authority is not able to change its AGC operating mode to correspond to current operating conditions.
R6.	The Balancing Authority failed to upload hourly Actual Net Interchange to the Interchange Software no later than 50 minutes after each hour, but uploaded the required data in less than or equal to two hours.	The Balancing Authority failed to upload hourly Actual Net Interchange to the Interchange Software no later than 50 minutes after each hour, but uploaded the required data in less than or equal to four hours.	The Balancing Authority failed to upload hourly Actual Net Interchange to the Interchange Software no later than 50 minutes after each hour, but uploaded the required data in less than or equal to six hours.	The Balancing Authority failed to upload hourly Actual Net Interchange to the Interchange Software no later than 50 minutes after each hour, but uploaded the required data in more than six hours.
R7.	NA	NA	NA	The Balancing Authority making a month-end adjustment failed to input that value as part of its Net Actual Interchange.
R8.	NA	NA	NA	The Balancing Authority making a month-end adjustment failed to add that value to its accumulated Primary Inadvertent Interchange.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	February 4, 2003	Effective Date.	New
1	October 17, 2006	Created Standard from Procedure.	Errata
1	February 6, 2007	Changed the Standard Version from 0 to 1 in the Version History Table.	Errata
1	February 6, 2007	The upper limit bounds to the amount of Automatic Time Error Correction term was inadvertently omitted during the Standard Translation. The bound was added to the requirement R1.4.	Errata
1	February 6, 2007	The statement "The Time Monitor may declare offsets in 0.001-second increments" was moved from TEoffset to TDadj and offsets was corrected to adjustments.	Errata
1	February 6, 2007	The reference to seconds was deleted from the TE offset term.	Errata
1	June 19, 2007	The standard number BAL-STD-004-1 was changed to BAL-004-WECC-01 to be consistent with the NERC Regional Reliability Standard Numbering Convention.	Errata
2	December 19, 2012	Adopted by NERC Board of Trustees.	
2	October 16, 2013	A FERC Letter Order was issued on October 16, 2013, approving BAL-004-WECC-02. This standard will become enforceable on April 1, 2014.	

Version	Date	Action	Change Tracking
3	December 6, 2017	Approved by the WECC Board of Directors.	Five-year review. The project: 1) relocates the Background section to the preamble of the Guidance section, 2) adds On-Peak and Off-Peak parameters in Requirement R1/M1, 3) addresses WECC Interchange Tool software successors throughout, 4) conforms the document to current drafting conventions (R1/M1, R4/M4), and 5) addresses non-substantive syntax and template concerns.
3	February 8, 2018	Adopted by the NERC Board of Trustees.	
3	May 30, 2018	FERC Order issued approving BAL-004-WECC-3. Docket No. RD18-2-000. Effective Date October 1, 2018.	
4	March 13, 2024	WECC Board of Directors Approved	This project: 1) expands the existing Background section, 2) creates a Standard-specific definition (Interchange Software); 3) creates a requirement to use the Interchange Software; 4) addresses treatment of Balancing Authorities that do not have a full year of operating data; 5) consolidates and clarifies requirements; and 6) updates the document to NERC's newest templates.

Standard Attachments

Not used.

G. Rationale

Nomenclature Update

To conform to NERC's definitional approach, the legacy term Net Actual Interchange (NAI) was replaced with Actual Net Interchange (NI_A). Net Scheduled Interchange (NSI) was replaced with Scheduled Net Interchange (NI_S). The legacy terms and the updated terms are synonymous.

Requirement R1:

The goal of Requirement R1 is to ensure a consistent ATEC calculation within the WI.

Because ATEC is an automatic process, allowing inconsistent calculation of ATEC will cause imbalance in accumulations.

Requirement R2:

The goal of Requirement R2 is to limit the amount of PII_{accum} that a Balancing Authority can have at the end of each month.

To reach the goal, each Balancing Authority should ensure that the absolute value of its PII_{accum} for both the on-peak period and the off-peak period each individually does not exceed 150% of the previous year's Peak Demand for load-serving Balancing Authorities, and 150% of the previous year's peak generation for generation-only Balancing Authorities. The Balancing Authority is required to keep each PII_{accum} period within the limit. For example, the Balancing Authorities actions may include:

- Identifying and correcting the source of any metering or accounting error(s) and recalculating the hourly Primary Inadvertent Interchange **(**PII_{hourly}) and the PII_{accum} from the time of the error;
- Validating the implementation of ATEC; or
- Setting L_{max} equal to L_{10}.until the PII_{accum} is below the limit in Requirement R1.

This approach is required because PII_{accum} may grow from month-end adjustments and metering errors, even with the inclusion of I_{ATEC} in the ACE equation.

Requirement R3:

The goal of Requirement R3 is to promote: 1) the timely correction of errors in the calculation of PII and PII_{accum}, and 2) the accurate, fair, and timely payback of accumulated PII balances.

When a Balancing Authority finds an error in the calculation of its PII, the Balancing Authority needs time to correct the error and recalculate PII and PII_{accum}.

Hourly adjustments to hourly Inadvertent Interchange (II) require a recalculation of the corresponding hourly PII value, the corresponding PII_{accum}, and all subsequent PII_{accum} for every hour up to the current hour.

The drafting team selected 90 days as a reasonable amount of time to correct an error and recalculate PII and PII_{accum}, since recalculation of PII and PII_{accum} is not a real-time operations reliability issue. As PII hourly is corrected, then PIIaccum should be recalculated.

Requirement R4:

The goal of Requirement R4 is to promote fair and timely payback of PII_{accum} balances by ensuring that ATEC remains in service whenever possible.

When a Balancing Authority is not participating in ATEC, payback of PII_{accum} is delayed.

The limit of 24 hours per quarter discourages a Balancing Authority from withdrawing ATEC participation, for example, for economic gain during selected hours. If the limits were increased to 60 hours, a Balancing Authority could technically withdraw ATEC participation for one hour from Monday to Friday.

Requirement R5:

A review of NERC Standards conducted by the Version 4 drafting team concluded that this Requirement is best located in a Standard focused on Automatic Generator Control (AGC). However, until an AGC-specific Standard is drafted, the Requirement should not be retired.

The goal of Requirement R5 is to ensure that AGC has the ability to respond to varying operating conditions.

Requirement R6:

Not used.

Requirement R7:

Not used.

Requirement R8:

Not used.

A. Introduction

1. **Title:** Cyber Security – Communications between Control Centers
2. **Number:** CIP-012-2
3. **Purpose:** To protect the confidentiality, integrity, and availability of Real-time Assessment and Real-time monitoring data transmitted between Control Centers.
4. **Applicability:**

4.1. Functional Entities: The requirements in this standard apply to the following functional entities, referred to as “Responsible Entities,” that own or operate a Control Center.

4.1.1. Balancing Authority

4.1.2. Generator Operator

4.1.3. Generator Owner

4.1.4. Reliability Coordinator

4.1.5. Transmission Operator

4.1.6. Transmission Owner

4.2. Exemptions: The following are exempt from Reliability Standard CIP-012-2:

4.2.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.2. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3. A Control Center that transmits to another Control Center Real-time Assessment or Real-time monitoring data pertaining only to the generation resource or Transmission station or substation co-located with the transmitting Control Center.

5. **Effective Date*:**

*Mandatory BC Effective Date: October 1, 2027

B. Requirements and Measures

R1. The Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) to mitigate the risks posed by unauthorized disclosure, unauthorized modification, and loss of availability, of data used in Real-time Assessment and Real-time monitoring while such data is being transmitted between any applicable Control Centers. The Responsible Entity is not required to include oral communications in its plan. The plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*Identification of method(s) used to mitigate the risk(s) posed by unauthorized disclosure and unauthorized modification of data used in Real-time Assessment and Real-time monitoring while such data is being transmitted between Control Centers;

1.1. Identification of method(s) used to mitigate the risk(s) posed by unauthorized disclosure and unauthorized modification of data used in Real-time Assessment and Real-time monitoring while such data is being transmitted between Control Centers;

1.2. Identification of method(s) used to mitigate the risk(s) posed by the loss of the ability to communicate Real-time Assessment and Real-time monitoring data between Control Centers;

1.3. Identification of method(s) used to initiate the recovery of communication links used to transmit Real-time Assessment and Real-time monitoring data between Control Centers;

1.4. Identification of where the Responsible Entity implemented method(s)as required in Parts 1.1 and 1.2; and

1.5. If the Control Centers are owned or operated by different Responsible Entities, identification of the responsibilities of each Responsible Entity for implementing method(s) as required in Parts 1.1, 1.2, and 1.3.

M1. Examples of evidence may include, but are not limited to, documented plan(s) that meet the mitigation objective of Requirement R1 and documentation demonstrating the implementation of the plan(s). Examples of methods identified in the plan(s) may include, but are not limited to, one or more of the following for each Part:

Part 1.1

- Methods of mitigation used to protect against the unauthorized disclosure and unauthorized modification of the data (e.g., data masking, encryption/decryption) while such data is being transmitted between Control Centers
- Physical access restrictions to unencrypted portions of the network

Part 1.2

- Identification of alternative communication paths or methods between Control Centers
- Procedures explaining the use of alternative systems or methods for providing for the availability of the data
- Service level agreements with carriers containing high availability provisions

- Availability or uptime reports for equipment supporting the transmission of Real-time Assessment and Real-time monitoring data

Part 1.3

- Contract, memorandum of understanding, meeting minutes, agreement or other information outlining the methods used for recovery
- Methods for the recovery of links such as standard operating procedures, applicable sections of CIP-009 recovery plan(s), or similar technical recovery plans
- Documentation of the process to restore assets and systems that provide communications
- Process or procedure to contact a communications link vendor to initiate and or verify restoration of service

Part 1.4

- Descriptions or logical diagrams indicating where the implemented methods reside
- Identification of points within the infrastructure where the implemented methods reside
- Third party Agreements detailing where the methods are implemented if such methods are implemented by the third party

Part 1.5

- Contract, memorandum of understanding, meeting minutes, agreement, or other documentation outlining the responsibilities of each entity

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:**
   The British Columbia Utilities Commission

   1.2. **Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

   - The Responsible Entities shall keep data or evidence of each Requirement in this Reliability Standard for three calendar years.
   - If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
   - The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Responsible Entity documented its plan(s), but failed to include one of the applicable Parts of the plan as specified in Requirement R1.	The Responsible Entity documented its plan(s), but failed to include two of the applicable Parts of the plan as specified in Requirement R1.	The Responsible Entity failed to document its plan(s) for Requirement R1; OR The Responsible Entity failed to implement three or more Parts of its plan(s) for Requirement R1, except under CIP Exceptional Circumstances.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan.
- Technical Rationale for CIP-012-2.

Version History

Version	Date	Action	Change Tracking
1		Respond to FERC Order No. 822	New
1	August 16, 2018	Adopted by NERC Board of Trustees	
1	January 23, 2020	FERC Order issued approving CIP-012-1Docket No. RM18-20-000	
2	December 12, 2023	Adopted by NERC Board of Trustees	Revised under Project 2020-04
2	May 23, 2024	FERC Order issued approving CIP-012-2 Docket No. RD24-3-000	

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-4**
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date*:** See BC Implementation Plan for EOP-011-4

*** Mandatory BC Effective Date: October 1, 2026 and as per BC Implementation Plan**

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. Cold weather conditions; and

1.2.6.2. Extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

8.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

8.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:**
   The British Columbia Utilities Commission

   1.2. **Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

   - The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
   - The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
   - The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
   - The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
   - The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

A. Introduction

1. **Title:** **Extreme Cold Weather Preparedness and Operations**
2. **Number:** EOP-012-2
3. **Purpose:** To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its applicable generating units.
4. **Applicability:**

    4.1. Functional Entities:

    4.1.1. Generator Owner

    4.1.2. Generator Operator

    4.2. Facilities:

    4.2.1. Bulk Electric System (BES) generating units. For purposes of this standard, the term "generating unit" subject to these requirements refers to the following Bulk Electric System (BES) resources:

    4.2.1.1. A Bulk Electric System generating resource identified in the BES definition, inclusion I2 and I4; or

    4.2.1.2. A Blackstart Resource, identified in the BES definition, inclusion I3.

5. **Effective Date*:** See BC Implementation Plan for EOP-012-2

B. Requirements and Measures

R1. At least once every five calendar years, each Generator Owner shall, for each of its applicable generating unit(s): [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]

1.1. Calculate the Extreme Cold Weather Temperature for each of its applicable unit(s) and identify the calculation date and source of temperature data; and

1.1.1. If the re-calculated Extreme Cold Weather Temperature is lower than the previous Extreme Cold Weather Temperature, the entity shall review and update its cold weather preparedness plan(s) under Requirement R4 within six (6) months of the recalculation. If new corrective actions are needed to provide the required operational capability under Requirement R2 or R3, the entity shall develop a Corrective Action Plan within 6 months of the recalculation.

1.2. Identify generating unit(s) cold weather data, to include:

1.2.1. Generating unit(s) operating limitations in cold weather to include:

* Mandatory BC Effective Date: October 1, 2026 and as per BC Implementation Plan

1.2.1.1. Capability and availability;

1.2.1.2. Fuel supply and inventory concerns;

1.2.1.3. Start-up issues;

1.2.1.4. Fuel switching capabilities; and

1.2.1.5. Environmental constraints.

1.2.2. Generating unit(s) minimum:

- Design temperature, and if available, the concurrent wind speed and precipitation;
- Historical operating temperature at least one hour in duration, and if available, the concurrent wind speed and precipitation; or
- Current cold weather performance temperature determined by an engineering analysis, which includes the concurrent wind speed and precipitation.

M1. Each Generator Owner will have evidence documenting its Extreme Cold Weather Temperature calculation and design information, operating data, or engineering analysis that supports its generating unit minimum temperature.

R2. Applicable to generating units with a commercial operation date on or after October 1, 2027: Each Generator Owner, for each generating unit that has a calculated Extreme Cold Weather Temperature at or below 32 degrees Fahrenheit (zero degrees Celsius) as determined in Requirement R1, and that self-commits or is required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius),[1] shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

- Implement freeze protection measures to protect Generator Cold Weather Critical Components that provide the capability to operate at the unit(s)' Extreme Cold Weather Temperature with sustained concurrent twenty (20) mph wind speed for (i) a period of not less than twelve (12) continuous hours, or (ii) the maximum operational duration for intermittent energy resources if less than twelve (12) continuous hours; or
- Develop a Corrective Action Plan(s) to add new or modify existing or previously planned freeze protection measures to provide the capability to operate at the unit(s)' Extreme Cold Weather Temperature with a sustained concurrent twenty (20) mph wind speed for (i) a period of not less than

[1] Generating unit(s) that do not self-commit or are not required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), but may be called upon to operate in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), are exempt from this requirement.

twelve (12) continuous hours, or (ii) the maximum operational duration for intermittent energy resources if less than twelve (12) continuous hours.

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a Corrective Action Plan for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating unit(s) minimum temperature under Requirement R1 Part 1.2.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, and Corrective Action Plan(s).

R3. Applicable to generating unit(s) in commercial operation prior to October 1, 2027: Each Generator Owner, for each generating unit that has a calculated Extreme Cold Weather Temperature at or below 32 degrees Fahrenheit (zero degrees Celsius) as determined in Requirement R1, and that self-commits or is required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius),[2] shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

- Implement freeze protection measures to protect Generator Cold Weather Critical Components that provide the capability to operate at the unit(s)' Extreme Cold Weather Temperature; or
- Develop a Corrective Action Plan to add new or modify existing freeze protection measures to provide the capability to operate at the unit(s)' Extreme Cold Weather Temperature.

M3. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R3, or it has developed a Corrective Action Plan for the identified issues. Acceptable evidence may include, but is not limited to, the following (electronic or hardcopy format): Identification of generating unit(s) minimum temperature per Part 1.2.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, and Corrective Action Plan(s).

R4. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

[2] Generating unit(s) that do not self-commit or are not required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), but may be called upon to operate in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), are exempt from this requirement.

4.1. The lowest calculated Extreme Cold Weather Temperature for each unit, as determined in Requirement R1;[3]

4.2. The generating unit cold weather data, as determined in Requirement R1.2;

4.3. Documentation identifying Generator Cold Weather Critical Components;

4.4. Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which includes measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain); and

4.5. Annual inspection and maintenance of generating unit(s) freeze protection measures.

M4. Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R4. Examples of documentation to demonstrate a cold weather preparedness plan may include existing operating procedures, plans, checklists, or processes. Examples of documentation to demonstrate inspections and maintenance have been completed may include, but are not limited to, completed work order(s) from the Generator Owner's work management system and/or freeze protection checklists identifying the measures inspected and maintained.

R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M5. Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5.

R6. Each Generator Owner shall, for each generating unit that has a calculated Extreme Cold Weather Temperature at or below 32 degrees Fahrenheit (zero degrees Celsius) as determined in Requirement R1 and that self-commits or is required to operate at

[3] Generator Owners shall include the lowest calculated Extreme Cold Weather Temperature for the unit, even where subsequent periodic re-calculations under Requirement R1 Part 1.1 cause an increase in the Extreme Cold Weather Temperature.

or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius),[4] develop a Corrective Action Plan when the generating unit experiences a Generator Cold Weather Reliability Event. The Corrective Action Plan shall be developed within 150 days or by July 1, whichever is earlier, and contain at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1. A summary of the identified cause(s) for the Generator Cold Weather Reliability Event, where applicable, and any relevant associated data;

6.2. A review of applicability to similar equipment at generating units owned by the Generator Owner; and

6.3. An identification of operating limitations or impacts to the cold weather preparedness plan that would apply until execution of the corrective action(s) identified in the Corrective Action Plan.

M6. Each Generator Owner will have documented evidence that it developed a Corrective Action Plan following a Cold Weather Reliability Event at an applicable unit in accordance with Requirement R6. Acceptable evidence may include, but is not limited to, the following dated documentation (electronic or hardcopy format): Corrective Action Plan(s) and updated cold weather preparedness plan(s) where indicated as needed by the Corrective Action Plan.

R7. Each Generator Owner, for each Corrective Action Plan developed pursuant to Requirements R1, R2, R3, or R6, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1. Include a timetable for implementing the selected corrective action(s) that shall:

7.1.1. List the action(s) which address(es) existing equipment or freeze protection measures, if any, to be completed within 24 calendar months of completing development of the Corrective Action Plan;

7.1.2. List the action(s) which require(s) new equipment or freeze protection measures, if any, to be completed within 48 calendar months of completing development of the Corrective Action Plan; and

7.1.3. List the updates to the cold weather preparedness plan required under Requirement R4 to identify the updates or additions to the Generator Cold Weather Critical Components and their freeze protection measures;

7.2. Implement the Corrective Action Plan in accordance with the specified timetables in Requirement R7 Part 7.1;

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[4] Generating unit(s) that do not self-commit or are not required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), but may be called upon to operate in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), are exempt from this requirement.

7.3. Update the Corrective Action Plan action(s) and timetable(s), with justification, if corrective action(s) change or timetable(s) exceed the timelines in Requirement R7 Part 7.1; and

7.4. Document in a declaration, with justification, any Generator Cold Weather Constraint that precludes the Generator Owner from implementing selected action(s) contained within the Corrective Action Plan.

M7. Each Generator Owner shall have dated evidence that demonstrates it implemented each Corrective Action Plan, including updating actions or timetables, or has explained in a declaration why corrective actions are not being implemented in accordance with Requirement R8. Acceptable evidence may include, but is not limited to, the following dated documentation (electronic or hardcopy format): records that document the implementation of each Corrective Action Plan and the completion of actions for each Corrective Action Plan including revision history of each Corrective Action Plan and, if applicable, justification to support any changes to corrective action(s) identified in the Corrective Action Plan or timetables exceeding the timelines in Requirement R7 Part 7.1. For each Corrective Action Plan applying to multiple generating units, the timetable shall reflect implementation at each unit addressed in the Corrective Action Plan. Evidence may also include work management program records, work orders, and maintenance records. Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.

R8. Each Generator Owner that creates a Generator Cold Weather Constraint declaration shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. Review the Generator Cold Weather Constraint declaration at least every five calendar years or as needed when a change of status to the Generator Cold Weather Constraint occurs; and

8.2. Update the operating limitations associated with capability and availability under Requirement R1 Part R1.2 if applicable.

M8. Each Generator Owner shall have dated evidence that demonstrates it performed the review and updated operating limitations as needed. Acceptable evidence may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the performance of the review and update to the operating limitations, as needed.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

The British Columbia Utilities Commission

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Generator Owner shall retain data or evidence to support its current Extreme Cold Weather Temperature calculation and generating unit cold weather data, plus each calculation or revision since the last audit, for Requirement R1 and Measure M1.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R2 or R3 is complete, whichever timeframe is greater, for Requirements R2 and R3 and Measures M2 and M3.
- The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R4 and Measure M4.
- The Generator Owner or Generator Operator shall keep data or evidence to show compliance for three years for Requirement R5 and Measure M5.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R6 is complete, whichever timeframe is greater, for Requirement R6 and Measure M6.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan is complete, whichever time frame is greater, for Requirement R7 and Measure M7.

- The Generator Owner shall maintain data or evidence to support its current Generator Cold Weather Constraint declaration, plus each revision since the last audit, for Requirement R8 and Measure M8.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner did not calculate the Extreme Cold Weather Temperature and identify generating unit(s) cold weather data in accordance with Requirement R1 for 5% or less of its applicable units.	The Generator Owner did not calculate the Extreme Cold Weather Temperature and identify generating unit(s) cold weather data in accordance with Requirement R1 for more than 5%, but less than or equal to 10% of its applicable units.	The Generator Owner did not calculate the Extreme Cold Weather Temperature and identify generating unit(s) cold weather data in accordance with Requirement R1 for more than 10%, but less than or equal to 20% of its applicable units.	The Generator Owner did not calculate the Extreme Cold Weather Temperature and identify generating unit(s) cold weather data in accordance with Requirement R1 for more than 20% of its applicable units.
R2.	The Generator Owner did not have freeze protection measure(s) for its applicable unit(s) meeting the criteria in Requirement R2 for 5% or less of its applicable units. OR The Generator Owner did not develop a Corrective Action Plan to implement appropriate freeze protection measures for 5% or less of its applicable units.	The Generator Owner did not have freeze protection measure(s) for its applicable unit(s) meeting the criteria in Requirement R2 for more than 5%, but less than or equal to 10% of its applicable units. OR The Generator Owner did not develop a Corrective Action Plan for more than 5%, but less than or equal to 10% of its applicable units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 10%, but less than or equal to 20% of its applicable units. OR The Generator Owner did not develop a Corrective Action Plan for more than 10%, but less than or equal to 20% of its applicable units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 20% of its applicable units. OR The Generator Owner did not develop a Corrective Action Plan for more than 20% of its applicable units.
R3.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R3 for	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R3 for	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R3 for	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R3 for

	5% or less of its applicable units. OR The Generator Owner did not develop a Corrective Action Plan as required by Requirement R3 for 5% or less of its applicable units.	more than 5%, but less than or equal to 10% of its applicable units. OR The Generator Owner did not develop a Corrective Action Plan as required by Requirement R3 for more than 5%, but less than or equal to 10% of its applicable units.	more than 10%, but less than or equal to 20% of its applicable units. OR The Generator Owner did not develop a Corrective Action Plan as required by Requirement R3 for more than 10%, but less than or equal to 20% of its applicable units.	more than 20% of its applicable units. OR The Generator Owner did not develop a Corrective Action Plan as required by Requirement R3 for more than 20% of its applicable units.
R4.	The Generator Owner implemented a cold weather preparedness plan(s) but failed to maintain it.	The Generator Owner's cold weather preparedness plan failed to include one of the applicable Parts within Requirement R4.	The Generator Owner had and maintained a cold weather preparedness plan(s) but failed to implement it. OR The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R4.	The Generator Owner does not have a cold weather preparedness plan(s). OR The Generator Owner's cold weather preparedness plan failed to include three or more of the applicable requirement parts within Requirement R4.
R5.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • one applicable personnel at a single generating unit; or	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • two applicable personnel at a single generating unit; or	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • three applicable personnel at a single generating unit; or	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • four or more applicable personnel at a single generating unit; or

	• 5% or less of its total applicable personnel.	• more than 5%, but less than or equal to 10% of its total applicable personnel.	• more than 10%, but less than or equal to 15% of its total applicable personnel.	• more than 15% of its total applicable personnel.
R6.	The Generator Owner developed a Corrective Action Plan, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner's Corrective Action Plan failed to comply with one of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's Corrective Action Plan failed to comply with two of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's Corrective Action Plan failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a Corrective Action Plan, as required by Requirement R6.
R7.	The Generator Owner implemented a Corrective Action Plan, but failed to update the Corrective Action Plan when corrective action(s) changed in accordance with Requirement R7.	The Generator Owner implemented a Corrective Action Plan, but failed to include a timetable for implementing the selected corrective actions meeting the criteria of Requirement R7 Part 7.1.	The Generator Owner implemented a Corrective Action Plan, but failed to implement the Corrective Action Plan within the specified timetable or failed to update the Corrective Action Plan, with justification, when timetable(s) exceeded the timelines in Requirement R7 Part 7.1.	The Generator Owner failed to implement a Corrective Action Plan or failed to document in a declaration why corrective actions are not being implemented in accordance with Requirement R7.
R8.	N/A	N/A	The Generator Owner failed to comply with one of the elements in Requirement R8, Parts 8.1 through 8.2.	The Generator Owner failed to comply with all of the elements in Requirement R8, Parts 8.1 through 8.2.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	October 1, 2024	Drafted by Project 2021-07	New
2	February 16, 2023	Revisions drafted by Project 2021-07 due to FERC Order and inquiry Recommendations.	Revisions
2	February 15,2024	Board Adopted	

A. Introduction

1. **Title:** Transmission Maintenance
2. **Number:** FAC-501-WECC-4
3. **Purpose:** To ensure the Transmission Owner of a path identified in the Table Revision Process, Attachment A, Major WECC Transfer Paths in the Bulk Electric System (Table), has a Transmission Maintenance and Inspection Plan (TMIP) for those paths, annually updates its TMIP, and adheres to the TMIP.
4. **Applicability**

   4.1 Transmission Owners maintaining paths listed on the Table.
5. **Facilities**

   5.1 Bulk Electric System Facilities, Elements, Transmission Lines, and other equipment as listed on Attachment A Transmission Maintenance and Inspection Plan (TMIP) Content, comprising the named paths on the Table.
6. **Effective Date*:**

B. Background

(This section may be removed from the standard to align with NERC's current trends. If so, the content will be provided to NERC as part of WECC's filing with a request for approval.)

In July and August of 1996, the Western Interconnection experienced two widespread outages resulting from inadequate vegetation management. In March 1997, the Western Systems Coordinating Council (WSCC) trustees created the WSCC Reliability Management System (RMS) Policy Group establishing a remedial contract-based operational agreement known as the RMS. Although the RMS was established in response to the 1996 vegetation-related outages, unlike the FAC-003-X Transmission Vegetation Management standard, neither the RMS nor those standards evolving from it had vegetation management as their primary purpose. Rather, the initial version of WECC's Regional Reliability Standards were designed to address the outages collectively by continuing operational practices addressed in the RMS.[1]

By February 2000, the WSCC translated the RMS into what would become the first version of NERC's mandatory Reliability Standards. In that process, the list of paths contained in the 2000 RMS, Table 4 migrated from the RMS into PRC-STD-005-1 (PRC), Transmission Maintenance, Attachment A, Table 2, Existing WECC Transfer Paths (BPTP), (Revised February 2006), and was permanently replaced with FAC-501-WECC-1 and 2, Transmission

[1] The initial version of WECC's regional Reliability Standards were colloquially referred to as Version Zero standards. Version Zero is not a term used in the NERC Glossary of Terms Used in Reliability Standards. (See Docket No. RR07-11-000, July 2007).

*** Mandatory BC Effective Date: January 30, 2026**

Maintenance (Version 2, 2018).

The paths listed in the Table did not change between 2000 and 2020. Neither the RMS nor the filings of PRC-STD-005-1, FAC-501-WECC-1 or 2 explain *why* the specific paths were added to the Table, except that the RMS defines those paths as being monitored by the "Security Coordinator."

The addition of the Table Revision Process (Process) is intended to provide a streamlined development procedure for adding, removing or modifying paths listed on the Table. Specific equipment comprising a path can be identified on FAC-501-WECC-4, Attachment A, Transmission Maintenance and Inspection Plan.

C. Requirements and Measures

R1. Each Transmission Owner shall have a TMIP that includes, at a minimum, each of the items listed in Attachment A, Transmission Maintenance and Inspection Plan (TMIP) Content. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M1. Each Transmission Owner will have evidence that it has a TMIP detailing each of the items listed in Attachment A, as required in Requirement R1.

R2. Each Transmission Owner shall annually update its TMIP to reflect all changes to its TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Transmission Owner will have evidence that it annually updated its TMIP, as required in Requirement R2. When an annual update shows no changes are required to the TMIP, evidence may include but is not limited to, attestation that the update was performed but showed no changes were required.

R3. Each Transmission Owner shall adhere to its TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M3. Each Transmission Owner will have evidence that it adhered to its TMIP, as required in Requirement R3. Evidence may include, but is not limited to:

1.1 The date(s) the patrol, inspection or maintenance was performed;

1.2 The equipment on which the maintenance was performed;

1.3 A description of the inspection results or maintenance performed.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

The British Columbia Utilities Commission

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity 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 Owners listed in section 4.1 shall keep data or evidence of Requirements R1-R3 for three calendar years, or since the last audit, whichever is longer.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Owner's TMIP did not include one of the items listed in Attachment A, as required in Requirement R1.	The Transmission Owner's TMIP did not include two of the items listed in Attachment A, as required in Requirement R1.	The Transmission Owner's TMIP did not include three of the items listed in Attachment A, as required in Requirement R1.	The Transmission Owner's TMIP did not include four or more of the items listed in Attachment A, as required in Requirement R1.
R2.	The Transmission Owner did not annually update its TMIP (within the 365 days following the last review), as required by R2.	The Transmission Owner did not update its TMIP within the last one year and 1 day (within the 366 days following the last review), as required by R2.	The Transmission Owner did not update its TMIP within the last two years and 1 day (within the 731 days following the last review), as required by R2.	The Transmission Owner did not update its TMIP within the last three years and 1 day (within the 1095 days following the last review), as required by R2.
R3.	The Transmission Owner failed to adhere to: 1) one transmission line maintenance item, or 2) one station maintenance item, as contained in its TMIP, as required in R3.	The Transmission Owner failed to adhere to: 1) two transmission line maintenance items; or, 2) two station maintenance items; or 3) any combination of two items taken from the above list, for items contained in its TMIP, as required in R3.	The Transmission Owner failed to adhere to: 1) three transmission line maintenance items; or, 2) three station maintenance items; or 3) any combination of three items taken from the above list, for items contained in its TMIP, as required in R3.	The Transmission Owner failed to adhere to: 1) four or more transmission line maintenance items; or, 2) four or more station maintenance items; or, 3) any combination of four or more items taken from the above list, for items contained in its TMIP, as required in R3.

E. Regional Variances

None.

F. Associated Documents

Table Revision Process (Process)

The Process is *not* part of this Standard.

The Process: 1) describes the procedure whereby paths are added to or removed from the Table Revision Process, Attachment A, Major WECC Transfer Paths in the Bulk Electric System, and 2) contains the sole-source, FERC-approved listing of paths known as Major WECC Transfer Paths in the Bulk Electric System.

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-005-1	
1	October 29, 2008	NERC BOT conditional approval	
1	April 21, 2011	FERC Approved in Order 751	
2	July 1, 2017	Approved by the WECC Board of Directors.	1) Conformed to newest NERC template and drafting conventions, 2) eliminated URLs, 3) clarified Attachment A, and Measure M3.
2	February 8, 2018	Adopted by the NERC Board of Trustees.	
2	May 30, 2018	FERC Order issued approving FAC-501-WECC-2. Docket No. RD18-5-000. Effective July 1, 2018.	
3		Withdrawn	
4	May 9, 2024	Adopted by the NERC Board of Trustees	
4	September 26, 2024	FERC Order issued approving FAC-501-WECC-4. Docket No. RD24-7-000	

Attachment A
Transmission Maintenance and Inspection Plan (TMIP) Content

The TMIP shall include, at a minimum, each of the following items:

1. Facilities

A list of Facilities, Elements, Transmission Lines, and other equipment comprising the named paths on the Table Revision Process (Process), Attachment A, Major WECC Transfer Paths in the Bulk Electric System (Table).

2. Maintenance Method

A description of the maintenance method(s) used for the equipment included in the TMIP.

The TMIP maintenance method may be any one of the following or any combination thereof, but must include at least one of the following:

- Performance-based
  - This approach conducts maintenance by first defining the outcome then designing a maintenance program to meet the end performance.
- Time-based
  - This approach conducts maintenance based on defined timelines or specific events.
- Condition-based
  - This approach conducts maintenance based on the current condition of equipment.
- Risk-based
  - This approach conducts maintenance proactively based on predictive modeling. This approach is a benefit/burden analysis weighing the cost of maintenance against the likelihood of component failure. Equipment posing a greater risk to reliability in the event of failure may be maintained more frequently than components posing a lower reliability risk in the event of failure.
- Original Equipment Manufacturer
  - This approach is based on the recommendations of the equipment manufacturer.

3. Periodicity

Based on the maintenance method(s) selected in Item 2 above, the TMIP shall include a specification of the periodicity at which the described maintenance will occur or under what circumstance it occurs.

4. Transmission Line Maintenance and Inspection

A description of each of the following for the transmission line(s) included in the TMIP:

a. Inspection requirements

b. Patrol requirements

c. Tower and wood pole structure management

5. Station Maintenance and Inspection

A description of each of the following for each station included in the TMIP:

a. Inspection requirements

b. Equipment maintenance for each of the following:

   1. Circuit breakers
   2. Power transformers, specifically including phase-shifting transformers, where present.
   3. Reactive devices, specifically including shunt capacitors, series capacitors, synchronous condensers, shunt reactors, and tertiary reactors, where present.

A. Introduction

1. **Title: Operations Planning**

2. **Number: TOP-002-5**

3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.

4. **Applicability:**

   4.1. Transmission Operator

   4.2. Balancing Authority

5. **Effective Date*:**

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include, but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include, but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include, but is not limited to dated operator logs, or email records.

*** Mandatory BC Effective Date: April 1, 2027**

R4. Each Balancing Authority shall have an Operating Plan(s) for the next day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch;

4.2 Interchange scheduling;

4.3 Demand patterns; and

4.4 Capacity and energy reserve requirements, including deliverability capability.

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include, but is not limited to dated operator logs or email records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include, but is not limited to dated operator logs or email records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or email records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or email records.

R8. Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Demand patterns;

8.3.3 Capacity and energy reserve requirements, including deliverability capability; and

8.3.4 Weather forecast.

M8. Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

The British Columbia Utilities Commission

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Balancing Authority shall retain the current Operating Process(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R8.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	
R4	The Balancing Authority has an Operating Plan, but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	The Balancing Authority did not notify one impacted entity or 5% or less of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify four or more entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next day operations as

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				identified in Requirement R4 to its Reliability Coordinator.
R8	N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Extreme Cold Weather Preparedness Technical Rationale and Justification for TOP-002-5

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
2	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

Version	Date	Action	Change Tracking
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
3	May 6, 2012	Revisions under Project 2007-03	Revised
3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised
4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. Order No. 817.	
5	October 23, 2023	Revisions under Project 2021-07	Revised
5	February 15, 2024	Adopted by Board of Trustees	Revisions under Project 2021-07
5	February 16, 2024	FERC approved TOP-002-5. Docket No. RD24-1-000.	
5	October 1, 2025	Effective Date	

A. Introduction

1. **Title:** Power System Stabilizer (PSS)
2. **Number:** VAR-501-WECC-4
3. **Purpose:** To ensure the Western Interconnection is operated in a coordinated manner under normal and abnormal conditions by establishing the performance criteria for WECC power system stabilizers.
4. **Applicability:**
   - **4.1** Generator Operator
   - **4.2** Generator Owner
5. **Facilities:** This standard applies to synchronous generators, connected to the Bulk Electric System, meeting the definition of Commercial Operation.
6. **Effective Date*:**

B. Requirements and Measures

R1. Each Generator Owner shall provide to its Transmission Operator, the Generator Owner's written Operating Procedure or other document(s) describing those known circumstances during which the Generator Owner's PSS will not be providing an active signal to the Automatic Voltage Regulator (AVR), within 180 days of any of the following events: *[Violation Risk Factor: Low] [Time Horizon: Planning Horizon]*

- The effective date of this standard;
- The PSS's Commercial Operation date; or
- Any changes to the PSS operating specifications.

M1. Each Generator Owner will have documented evidence that it provided to its Transmission Operator, within the time allotted as described in the procedures required under Requirement R1, written Operating Procedures or other document(s) describing those known circumstances during which the Generator Owner's PSS will not be providing an active signal to the AVR.

For auditing purposes, because Requirement R1 conditions are intended to be unchanged unless the Transmission Operator is otherwise notified, the Generator Owner only needs to provide the documentation to the Transmission Operator one time, or whenever the operating specifications change.
For auditing purposes, if a PSS is in service but is not providing an active signal to the AVR as described in Requirement R1, the disabled period does not count against the Requirement R2 mandate to be in service except as otherwise allowed.

R2. Each Generator Operator shall have its PSS in service while synchronized, except during any of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operating Assessment]*

- Component failure

* Mandatory BC Effective Date: October 1, 2025

- Testing of a Bulk Electric System Element affecting or affected by the PSS
- Maintenance
- As agreed upon by the Generator Operator and the Transmission Operator

A PSS that is out of service for less than 30 minutes does not create a violation of this Requirement, regardless of cause.

M2. Each Generator Operator will have documentation of each claimed exception specified in Requirement R2. Documentation may include, but is not limited to:

- A written explanation covering the bulleted exception that describes the circumstances of the exception as allowed in Requirement R2.
- Documented evidence that the Generator Operator and the Transmission Operator agreed the PSS would not be operating during a specified set of circumstances, where the exception is claimed under the last bullet of Requirement R2.

For auditing purposes, the presumption is that the PSS was in service unless otherwise exempted in Requirement R2. Evidence need only be provided to prove the circumstances during which the PSS was not in service for periods in excess of 30 minutes.

R3. Each Generator Owner shall tune its PSS to meet the following inter-area mode criteria, except as specified in Requirement R3, Part 3.5 below: *[Violation Risk Factor: Medium] [Time Horizon: Operating Assessment]*

3.1. PSS shall be set to provide the measured, simulated, or calculated compensated Vt/Vref frequency response of the excitation system and synchronous machine such that the phase angle will not exceed ± 30 degrees through the frequency range from 0.2 Hertz to the lesser of 1.0 Hertz or the highest frequency at which the phase of the Vt/Vref frequency response does not exceed 90 degrees.

3.2. PSS output limits shall be set to provide at least ±5% of the synchronous machine's nominal terminal voltage.

3.3. PSS gain shall be set to between 1/3 and 1/2 of maximum practical gain.

3.4. PSS washout time constant shall be no greater than 30 seconds.

3.5. Units that have an excitation system or PSS that is incapable of meeting the tuning requirements of Requirement R3 are exempt from Requirement R3 until the voltage regulator is either replaced or retrofitted such that the PSS becomes capable of meeting the tuning requirements.

M3. Each Generator Owner will have documented evidence that its PSS was tuned to meet the specifications of Requirement R3.

If the exception under Requirement R3, Part 3.5, is claimed, the Generator Owner will have documented evidence describing: 1) the conditions that render the PSS incapable of meeting the tuning requirements, and 2) the date the voltage regulator was last replaced or retrofitted.

R4. Each Generator Owner shall install and complete start-up testing of a PSS on its generator within 180 days of either of the following events: *[Violation Risk Factor: Medium] [Time Horizon: Operational Assessment]*

- The Generator Owner connects a generator to the BES, after achieving Commercial Operation, and after the Effective Date of this standard.
- The Generator Owner replaces the voltage regulator on its existing excitation system, after achieving Commercial Operation for its generator that is connected to the BES, and after the Effective Date of this standard.

M4. Each Generator Owner will have evidence that it installed and completed start-up testing of a PSS on its generator within 180 days of either of the conditions described in Requirement R4, and when those conditions occur after the Effective Date of this standard.

The first bullet of Requirement R4 only applies to equipment on its initial (first energization) connection to the BES.

R5. Each Generator Owner shall repair or replace a PSS within 24 months of that PSS becoming incapable of meeting the tuning specifications stated in Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Operational Assessment]*

M5. Each Generator Owner will have evidence that it repaired or replaced its PSS within 24 months of that PSS becoming incapable of meeting the tuning specifications of Requirement R3. Evidence may include, but is not limited to, documentation of the date the PSS became incapable of meeting the Requirement R3 tuning specifications, and the date the PSS was returned to service, demonstrating that the span of time between the two events was less than 24 months.

C. Compliance

1. **Compliance Monitoring Process**

   1.1 **Compliance Enforcement Authority**:
   The British Columbia Utilities Commission

   1.2. **Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity 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.

   - Each Generator Operator shall keep evidence for all Requirements of the document for a period of three years plus calendar current.

R	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	NA	NA	NA	The Generator Owner failed to provide its PSS operating specifications to the Transmission Operator as required in Requirement R1.
R2	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 30 minutes but less than 60 minutes.	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 60 minutes but less than 120 minutes.	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 120 minutes but less than 180 minutes.	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 180 minutes.
R3	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, two times or fewer during the audit period.	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, three times during the audit period.	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, four times during the audit period.	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, five times or more during the audit period.
R4	NA	NA	NA	The Generator Owner failed to install on its generator a PSS, as required in Requirement R4.
R5	NA	NA	NA	The Generator Owner failed to repair or replace a non-operational PSS as required in Requirement R5.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for VAR-STD-002b-1	
1	October 28, 2008	Adopted by NERC Board of Trustees	
1	April 21, 2011	FERC Order issued approving VAR- 501-WECC-1 (FERC approval effective June 27, 2011; Effective Date July 1, 2011)	
2	November 13, 2014	Adopted by NERC Board of Trustees	
2	March 3, 2015	FERC letter order approved VAR-501-WECC-2	
3	February 9, 2017	Adopted by NERC Board of Trustees	
3	April 28, 2017	FERC letter order approved VAR-501-WECC-3	
3.1	August 10, 2017	Adopted by the NERC Board of Trustees	Errata
3.1	September 26, 2017	FERC letter order issued approving VAR-501-WECC-3.1	
4	December 6, 2022	WECC Standards Committee accepted a “no change “ recommendation followed by	Non-substantive changes were approved by the

		an information-only filing to NERC.	WECC Standards Committee as allowed in the WECC Reliability Standards Development Procedures. An information-only filing provided to NERC reflects the following: 1) updates to the template and syntax, 2) removal of stale-dated language from the Effective Date, 3) deletion of “For auditing purposes of…” from M4, 4) in the Guidance section, “dampen” was replaced with “damp”, and syntax was addressed deleting “still”, “of those”, “of the”, and “to ensure” was replaced with “ensuring”, and “wash out” was replaced with “washout.”
4	December 12, 2023	Board Approved	
4	January 30,2024	FERC Approved Letter Order: Docket No. RD24-2-000	
4	January 30, 2024	Effective Date	April 1, 2024

Guideline and Technical Basis

PSS systems are used to minimize real power oscillations by rapidly adjusting the field of the generator to damp the low-frequency oscillations.

It is necessary for large numbers of PSS devices to be in operation in the Western Interconnection to provide the required system damping while allowing for some units to be out of service whenever necessary.

Mandate to Install a PSS

Nothing in this Regional Reliability Standard (RSS) should be construed to require installation of a PSS *solely because* a PSS is not currently installed as of the Effective Date of this RRS. Rather, installation is only mandated on the occurrence of either triggering event described in Requirement R4, Bullet 1 or Bullet 2, after the Effective Date of the RRS.

It should be noted that a PSS is neither Transmission nor generation.

Requirement R1

Requirement R1 addresses normal operating conditions.

Requirement R1 recognizes that PSS systems have varying states, such as on, off, active, and non-active. As long as the PSS is operating in accordance with the documentation provided to the Transmission Operator, this is not considered a status change for purposes of this Standard.

This Requirement eliminates the requirement to count hours as required in the previous version of this Standard while also allowing the Generator Owner to create a unit-specific operating plan.

The intent of Requirement R1 is to provide the Transmission Operator, the PSS operating zone in which the PSS is "active" providing damping to the power system. Some PSS may be programmed to become "active" at a specified megawatt loading level and above while others may be programmed to be "active" in a particular band of megawatt loading levels and are "non-active" only when passing through the "rough zone" or some other band. A "rough zone" is a megawatt loading band in which the generator-turbine system could contribute to system instability.

Requirement R2

This Requirement only applies when the PSS is out of service for a period greater than 30 minutes.

Unlike Requirement R1, Requirement R2 addresses exceptions to normal operation.

The intent of Requirement R2 is to remove the previous requirement to log hours for PSS in service. In this Standard's previous version, the logged hours were totaled quarterly to meet the 98% in-service requirement. Instead of documenting the number of hours excluded, this Requirement simplifies the process by allowing the Generator Operator to communicate to the Transmission Operator the circumstances that render the PSS unavailable to the Transmission Operator (such as component failure, maintenance, and testing).

Requirement R3

Nothing in this RSS should be construed to mandate the design criteria for the *equipment* used to produce the tuning output of the PSS. Rather, Requirement R3 is intended to address the design criteria for the *tuning output* of the PSS.

Unlike the language in Requirement R5 that looks *backward* to address units that were once operating but are no longer capable of operating, Requirement R3 looks *forward*, requiring that units be tuned to the specified parameters.

The PSS transfer function should compensate the phase characteristics of the generator, exciter, and power (GEP) system transfer function so the compensated transfer function ((PSS(s) * GEP(s)) has a phase characteristic of ± 30 degrees in the frequency range.

The GEP(s) transfer function is a theoretical transfer function, and its phase characteristic cannot be directly measured during field tests (only via simulation). Thus, the Requirement recognizes the practical approach of measuring the frequency response between voltage reference set point and terminal voltage (Et/Vref) and using the phase characteristic of such frequency response as being the phase characteristic of GEP(s). The phase characteristic of Et/Vref is a better approximation to the phase characteristic of GEP(s) when the frequency response Et/Vref is obtained with the generator synchronized to the grid at its minimum stable power output.

In an effort to allow for reasonable washout time constants, the Requirement specifies 0.2 Hz as the applicable threshold. The 0.2 Hz threshold more closely aligns with the observed oscillation frequencies.

A properly tuned PSS should provide positive damping to the local mode of oscillation, which typically has a frequency higher than 1.0 Hz.

This Requirement modifies the requirement associated with the adjustment of the PSS gain. The standard no longer defines the PSS gain in terms of gain margin but instead requires the final PSS gain to be between 1/3 (10 dB) and 1/2 (6 dB) of the maximum practical gain that could be achieved during PSS commissioning. The maximum practical gain might be associated with the excessive noise or raised higher-frequency oscillations in the closed loop response (exciter mode) or any other form if there is inadequate closed-loop performance, as determined during PSS commissioning. It is now part of Measure M3 to show the field test results that led to the determination of the maximum practical gain.

Requirement R4

Requirement R4 requires a Generator Owner to install a PSS on new applicable units or when excitation systems are replaced or retrofitted on existing applicable units. This Requirement applies to new excitation systems and not to existing systems that do not have PSS. The Requirement also allows a reasonable amount of time for the commissioning of new PSS.

Requirement R5

Unlike the language in Requirement R3 that looks forward ensuring that a unit is tuned, Requirement R5 looks *backward.* Specifically, the language in Requirement R5, “becoming incapable,” indicates the unit was previously capable of meeting the tuning requirements in Requirement R3, but is no longer capable. Restated, Requirement R5 addresses units that were previously working but are now no longer working.

The intent of Requirement R5 is to remove the “tiered” approach to PSS repair/replacement following a failure. A simple, streamlined approach to allow the Generator Owner sufficient time to repair or replace a broken PSS has been written. Consideration has been given for the need to procure parts or new equipment, schedule an equipment/unit outage, and install and test the repaired or replaced PSS. It is recognized that in some instances, it may require (1) replacement of an AVR, and (2) the existence of a PSS, or both the AVR and the PSS may need to be replaced to achieve a functioning system.

The 24-month time frame is sufficient to return a functional, operating PSS to service.

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