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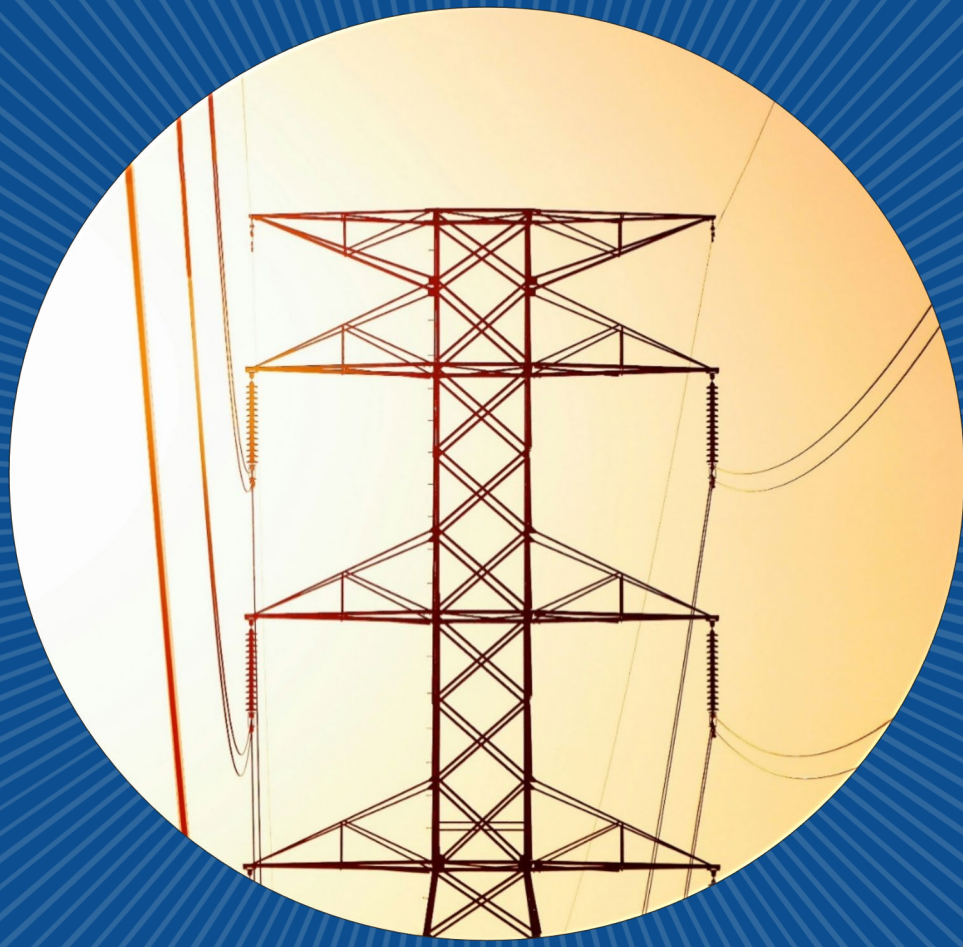
Upcoming Standards



NPCC Standards & Criteria

March 24, 2026

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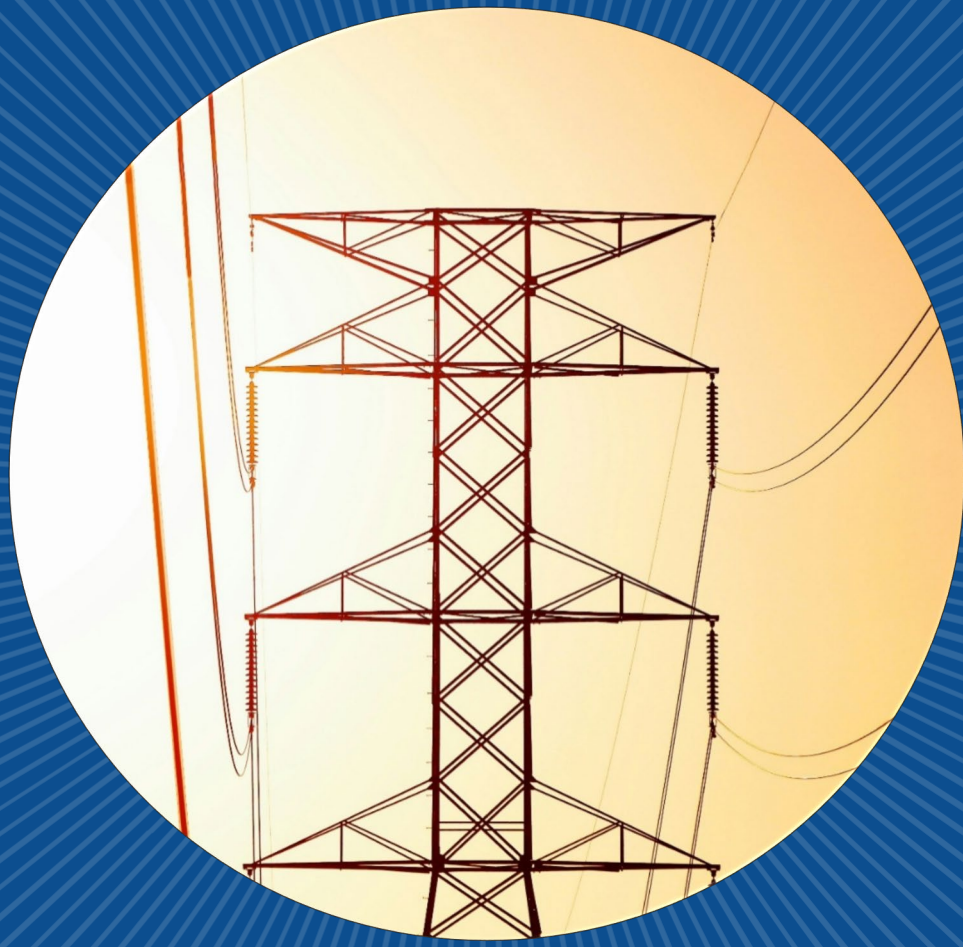

NPCC Standards & Criteria

March 24, 2026

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Agenda

- Introduction
- CIP-003-9
- CIP-012-2
- PRC-024-4
- PRC-029-1
- PRC-030-1
- TOP-003-7
- TPL-008-1
- Questions

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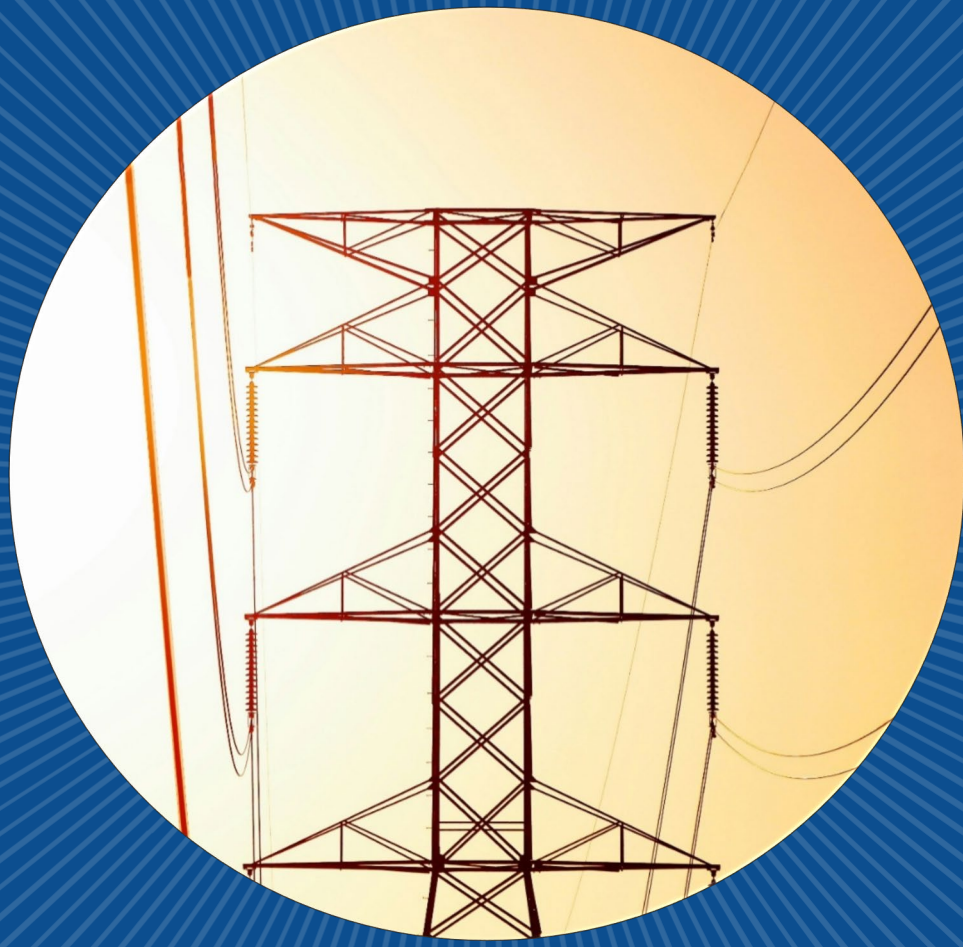
CIP-003-9

Security Management Controls



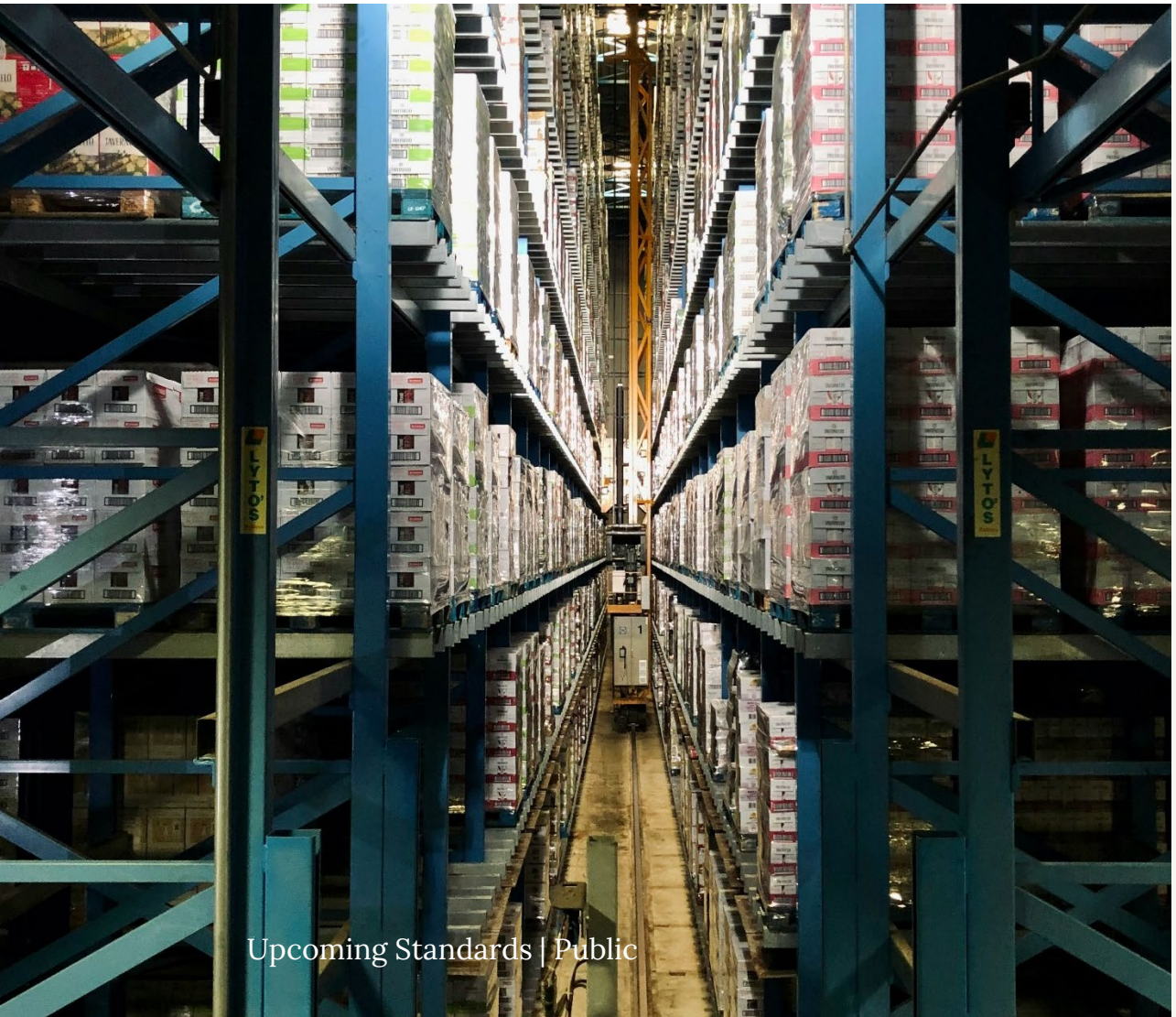
NPCC Standards & Criteria

Michael Ridolfino

March 24, 2026

Upcoming Standards | Public

NERC Supply Chain Risk Assessment Report



- 87% of all locations have Low Impact Bulk Electric System (BES) Cyber Systems, many with external connectivity.
- Two-thirds of Low Impact BES Cyber Systems have external connectivity.
- More than 50% of all generating resources allow third party electronic access.
- The combined effect of a coordinated attack could greatly impact BES reliability.
- These locations are not currently subject to CIP-005, CIP-010, and CIP-013.

Changes to Req's

- Cyber Security Policy in R1 must now document controls for vendor remote access to Low Impact BES Cyber Systems (BCS).
- R2 language was unchanged in this version of the standard. R2 requires entities with Low Impact BCS to implement a plan to protect those systems in accordance with Attachment 1.
- Detailed requirements for implementing R1.2.6 were added to Attachment 1.

R1. Each Responsible Entity shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. For its high impact and medium impact BES Cyber Systems, if any:

1.1.1. Personnel and training (CIP-004);

1.1.2. Electronic Security Perimeters (CIP-005) including Interactive Remote Access;

1.1.3. Physical security of BES Cyber Systems (CIP-006);

1.1.4. System security management (CIP-007);

1.1.5. Incident reporting and response planning (CIP-008);

1.1.6. Recovery plans for BES Cyber Systems (CIP-009);

1.1.7. Configuration change management and vulnerability assessments (CIP-010);

1.1.8. Information protection (CIP-011); and

1.1.9. Declaring and responding to CIP Exceptional Circumstances.

1.2. For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any:

1.2.1. Cyber security awareness;

1.2.2. Physical security controls;

1.2.3. Electronic access controls;

1.2.4. Cyber Security Incident response;

1.2.5. Transient Cyber Assets and Removable Media malicious code risk mitigation; ~~and~~

1.2.6. Vendor electronic remote access security controls; and

~~1.2.6.~~**1.2.7.** Declaring and responding to CIP Exceptional Circumstances.

Source: CIP-003-9 Redline to Last Approved

Changes to Attachments

New Section 6: Vendor Electronic Remote Access Security Controls

For assets containing low impact BES Cyber System(s) identified pursuant to CIP-002, that allow vendor electronic remote access, the Responsible Entity shall implement a process to mitigate risks associated with vendor electronic remote access, where such access has been established under Section 3.1. These processes shall include:

6.1

One or more method(s) for determining vendor electronic remote access;

6.2

One or more method(s) for disabling vendor electronic remote access; and

6.3

One or more method(s) for detecting known or suspected inbound and outbound malicious communications for vendor electronic remote access.

Changes to Violation Severity Levels (VSLs)

- R1
  - All VSLs updated to include “seven” sub-requirements of 1.2 for Low Impact.
- R2
  - Added language for vendor security controls:
    - Lower VSL – Implemented but failed to document,
    - Moderate VSL – Documented but failed to implement, and
    - High VSL – Failed to document or implement.

Implementation Plan

- Effective **April 1, 2026** (No phased implementation)
- Responsible Entities shall initially comply with Requirement R1, Part 1.2.6 on or before the effective date of CIP-003-9

Additional Resources

Project 2020-03

Supply Chain Low Impact Revisions

CIP-003-9 Standard

Cyber Security – Security Management Controls

Redline to Last Approved

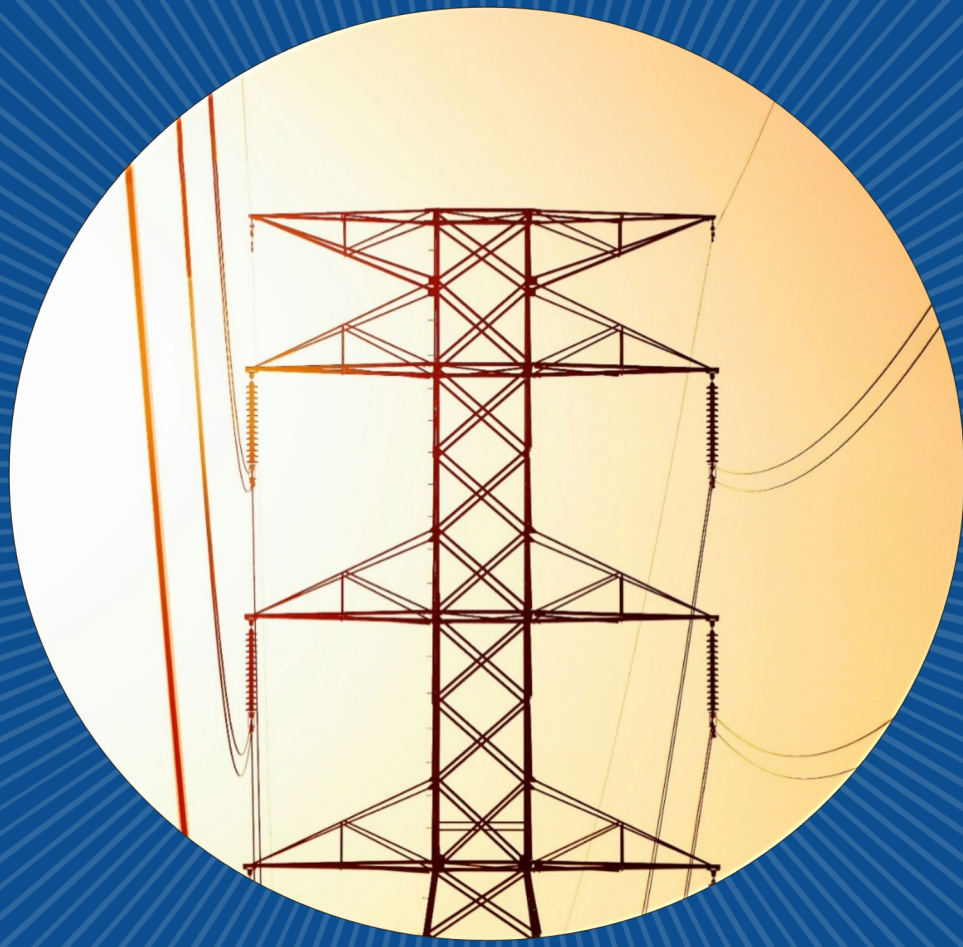
Implementation Plan

Technical Rationale

NPCC

CIP-012-2

Cyber Security Between Control Centers



NPCC Standards & Criteria

Patrick Davis

March 24, 2026

Upcoming Standards | Public

FERC Order No. 866

- Focus on ***availability*** of communication links and data between BES Control Centers
- Recognized communication link redundancy cannot always be guaranteed
- ***Recovery*** of compromised communication links
- Use of backup communication capability
- Required modifications to CIP-012-1

Changes to Requirement R1

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 ~~and~~, unauthorized modification ~~of~~, and loss of availability, of data used in Real-time Assessment and Real-time monitoring ~~data~~ 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]*

Source: CIP-012-2 Redline to Last Approved

"Availability" added to Requirement to address FERC Order 866 directive.

"Real-time Assessment and Real-time monitoring data" updated to "data used in" and "while such data" to avoid implying the associated data is a defined term.

Changes to Sub Requirements

1.1. Identification of ~~security protection~~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 ~~data~~ while such data is being transmitted between Control Centers;

1.2. Identification of ~~where~~method(s) used to mitigate the ~~Responsible Entity applied security protection~~risk(s) posed by the loss of the ability to communicate Real-time Assessment and Real-time monitoring ~~for transmitting Real-time Assessment and Real-time monitoring~~ data between Control Centers;

Source: CIP-012-2 Redline to Last Approved

Requirement R1.1

- Identification:
  - "security protections" updated to "methods"
- Data language updated to match parent requirement

Requirement R1.2

- Identification of methods used to mitigate risks:
  - "loss of data" updated to "loss of the ability to communicate …data"

Changes to Sub Requirements

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;

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

~~**1.3.**~~**1.5.** If the Control Centers are owned or operated by different Responsible Entities, identification of the responsibilities of each Responsible Entity for ~~applying security protection to the transmission of Real-time Assessment and Real-time monitoring data between those Control Centers.~~ implementing method(s) as required in Parts 1.1, 1.2, and 1.3.

Source: CIP-012-2 Redline to Last Approved

Requirement R1.3

- New Requirement
- Method used to initiate recovery of communication links

Requirements 1.4 & 1.5

- R1.4: identify where R1.1 and R1.2 method(s) are implemented
- R1.5 adds inclusion of new R1.3 sub-Requirement

Changes to Measures

- Identification of Methods:
  - Unauthorized Disclosure & Unauthorized Modification
  - Loss of Ability to Communicate
  - Used to Initiate Recovery of Communication Links
- Identification of Where:
  - Responsible Entity Implemented Methods
- Identification of Responsibilities:
  - Control Centers owned/operated by different Responsible Entities

M1. Examples of evidence may include, but ~~is~~are not limited to, documented plan(s) that meet the ~~security~~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

Source: CIP-012-2 Redline to Last Approved

Implementation Plan

- Effective **July 1, 2026**
- No phased implementation

Additional Resources

Project 2020-04

Modifications to CIP-012

CIP-012-2 Standard

Cyber Security – Communications between Control Centers

Redline to Last Approved

Implementation Plan

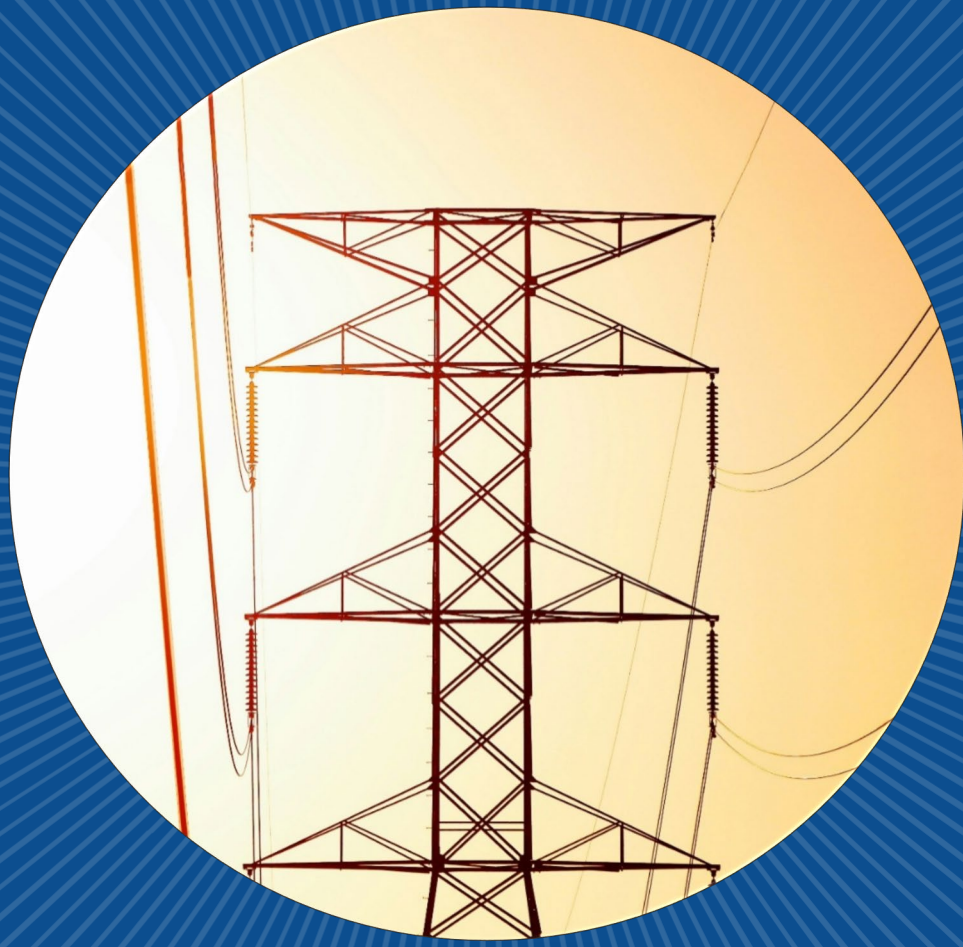
Technical Rationale

Implementation Guide

NPCC

PRC-024-4

Frequency and Voltage Protection Settings



NPCC Standards & Criteria

Michael Ridolfino

March 24, 2026

Upcoming Standards | Public

SAMS Whitepaper on Dynamic Reactive Resources

- NERC System Analysis and Modeling Subcommittee (SAMS) published a whitepaper which studied the applicability of reliability standards for transmission connected dynamic reactive resources.
- The whitepaper identified PRC-024 as a standard which was not applicable to dynamic reactive resources such as Synchronous Condensers, inverter-based resources, and power electronic based resources.
- These resources were not required to ride-through normal voltage and frequency excursions and the failure to do so could result in reliability concerns.

NERC Project 2020-02

PRC-024-4

- Frequency and voltage protection criteria for synchronous machines, synchronous condensers, and type 1 and type 2 wind resources (induction machines).

PRC-029-1

- Ride-through requirements for inverter-based resources, including Category 2 IBRs.

Changes to Standard

Facilities Section Expanded

- 4.2.2 Added new section mirroring language from 4.2.1 explicitly identifying “synchronous condensers” as

Functional Entities Expanded

- Generator Owners (GO) who apply protection specified in 4.2.1 or 4.2.2
- Transmission Owners (TO) who apply protection specified in

Additional Changes

Changes to Requirements

- Transmission Owner added to each requirement and measure

VSLs

- Transmission Owner added to each VSL

Regional Variance D.A. – Variance for Quebec Interconnection

- Removed reference to R1, R3, R4
- Change “generating resource” to “Facility” to cover dynamic resources
- Remove language specific to IBR settings

Attachments

- Added new facility types

Implementation Plan

Effective **October 1, 2026**

No phased implementation

Additional Resources

Project 2020-02

Modifications to PRC-024 (Generator Ride-through)

PRC-024-4 Standard

Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers

Redline to Last Approved

Implementation Plan

Technical Rationale

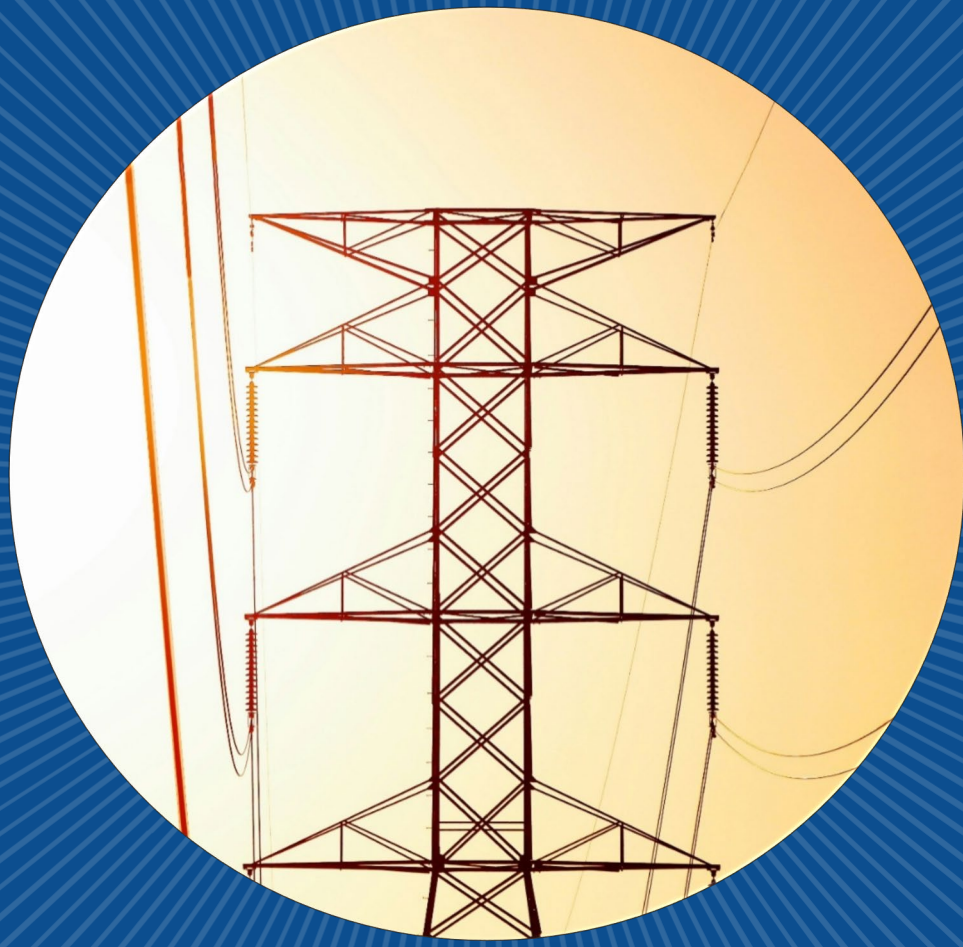
Whitepaper

Transmission Connected Dynamic Reactive Resources

NPCC

PRC-029-1

Frequency and Voltage Ride-through Requirements for Inverter-Based Resources



NPCC Standards & Criteria

Brian Deckert

March 24, 2026

Upcoming Standards | Public

Background

FERC Order No. 901

- Directs the creation of requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance.
- Project 2020-2 Modifications to PRC-024 (Generator Ride-through)
  - FERC 901 Milestone 2 project, filed by November 4, 2024.

Related Standards

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for IBRs
- PRC-030-1 Unexpected IBR Event Mitigation

New Definition

- Ride-through: The plant/facility remains connected and continues to operate through voltage or frequency system disturbances

Requirements

R1

- IBRs must meet the voltage Ride-through requirements in accordance with the “must Ride-through zone” as shown in Attachment 1.
- Except in following conditions:
  - Fault clearing
  - Hardware limitation, as described in R4
  - Non-fault phase angle jumps > 25 electrical degrees
  - Volts per Hz exceeding thresholds

R2

- During a voltage excursion, IBRs must:
  - Maintain real/reactive power delivery
  - Prioritize reactive power unless otherwise directed
  - Resume current exchange within 5 cycles after voltage recovery.
  - Restore real power within 1 second post-disturbance.

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-through Requirements for AC-Connected Wind IBR [13]

Voltage (per unit)[14]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[15]	N/A
≥ 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	3.00
< 0.70	Mandatory Operation Region	2.50
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 2: Voltage Ride-through Requirements for All Other IBR

Voltage (per unit)[16]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[17]	N/A
> 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	6.00
< 0.70	Mandatory Operation Region	3.00
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

Source: PRC-029-1

Requirements

R3

- IBRs must meet the frequency Ride-through requirements during frequency excursions event whereby the System frequency remains within the "must Ride-through zone" as shown in Attachment 2 and the absolute rate of change of frequency (RoCoF) magnitude is less than or equal to 5 Hz/second.

R4

- For equipment that is in-service by the effective date and has hardware limitations that prevent the IBR from meeting Ride-through criteria in R1-R3, GOs can receive an exemption.
  - Must document and submit evidence to Planning Coordinators, Transmission Operators, Reliability Coordinators, and the Compliance Enforcement Authority (CEA) within 12 months.

Attachment 2: Frequency Ride-Through Criteria

Table 3: Frequency Ride-through Capability Requirements

System Frequency (Hz)	Minimum Ride-Through Time (sec)
> 61.8	May trip
> 61.2	299
≤ 61.2 and ≥ 58.8	Continuous
< 58.8	299
< 57.0	May trip

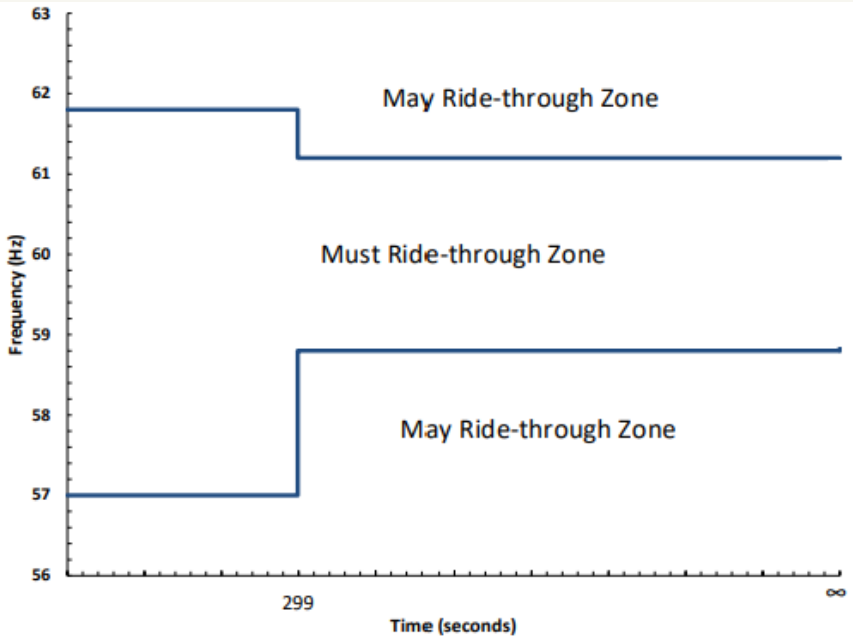


Figure 1: PRC-029 Frequency Ride-through Requirements

Source: PRC-029-1

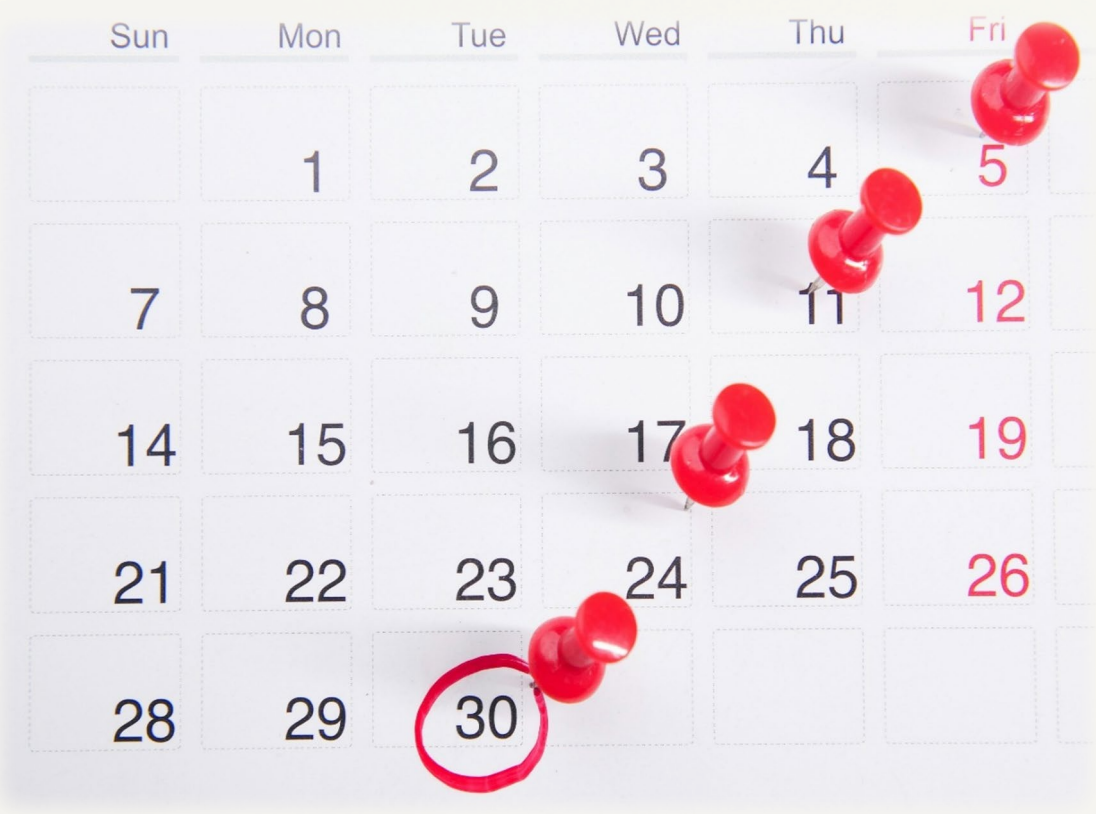
Phased-in Compliance

R1, R2, & R3

- Entities compliant with all design portions for BES IBRs by **October 1, 2026**.
  - Non-BES IBRs by **January 1, 2027**.
- Operational requirements compliance not required until the entity has established the required disturbance monitoring equipment capabilities in accordance with the Implementation Plan of PRC-028-1.

R4

- Entities compliant for BES IBRs by **October 1, 2026**.
  - Non-BES IBRs by **January 1, 2027**.



Implementation Plan PRC-028-1

BES IBRs

- R1 – R7
  - In commercial operation on/before April 1, 2025:
    - 50% by **December 31, 2028**
    - 100% by **January 1, 2030**
  - In commercial operation after April 1, 2025:
    - By **July 31, 2026,** or within 15 calendar months of commercial operation date, whichever is later
- R8
  - **January 1, 2026**

Non-BES IBRs

- R1 – R7
  - In commercial operation on/before May 15, 2026:
    - **January 1, 2030.**
  - In commercial operation after May 15, 2026:
    - By **July 31, 2026**, or the commercial operation date, whichever is later
- R8
  - **April 1, 2027**

Additional Resources

Project 2020-02

Modifications to PRC-024 (Generator Ride-through)

PRC-029 Standard

Frequency and Voltage Ride-through Requirements for Inverter-Based Resources

Implementation Plan

Technical Rationale

PRC-028-1 Standard

Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

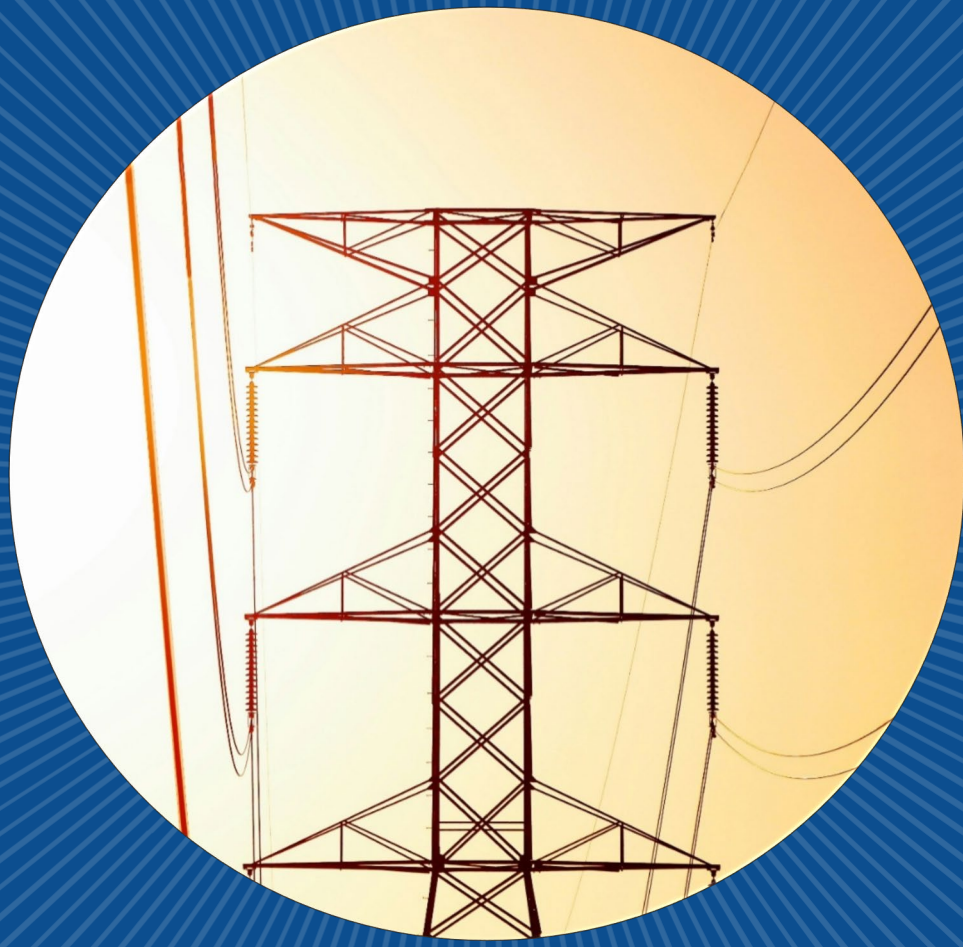
PRC-030-1 Standard

Unexpected Inverter-Based Resource Event Mitigation

NPCC

PRC-030-1

Unexpected Inverter-Based Resource Event Mitigation



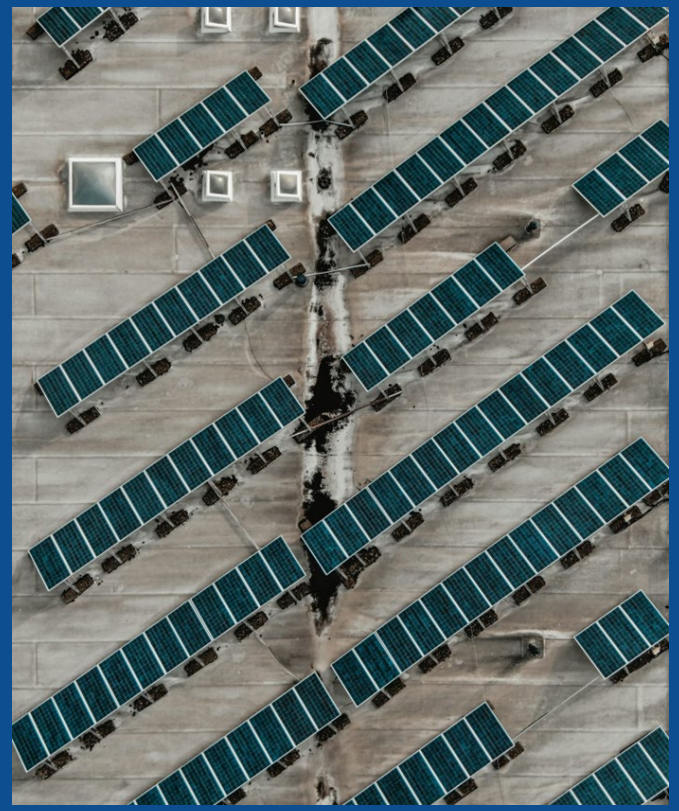
NPCC Standards & Criteria

Patrick Davis

March 24, 2026

Upcoming Standards | Public

Background



FERC Order 901

- Milestone 2
- Post-Event Performance Validation for IBRs
- GO's must perform post-event analytics
- Corrective Action Plans (CAPs)

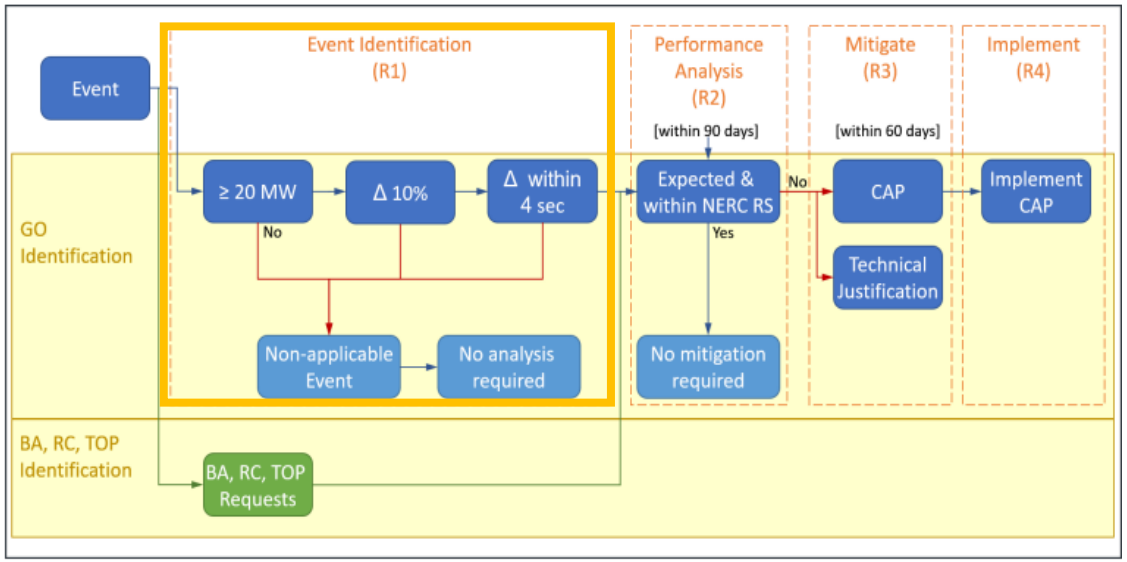
Industry Need

- Undesired performance of BPS-connected IBRs
- Unexpected or unwarranted loss of generation
- Identified through multiple NERC disturbance reports
- Need for analysis with root causes and mitigation

New Standard

- Separate from PRC-004
- Solely focused on IBRs
- Collaboration with BA, RC, TOP

Requirement R1



Source: PRC-030 Technical Rationale

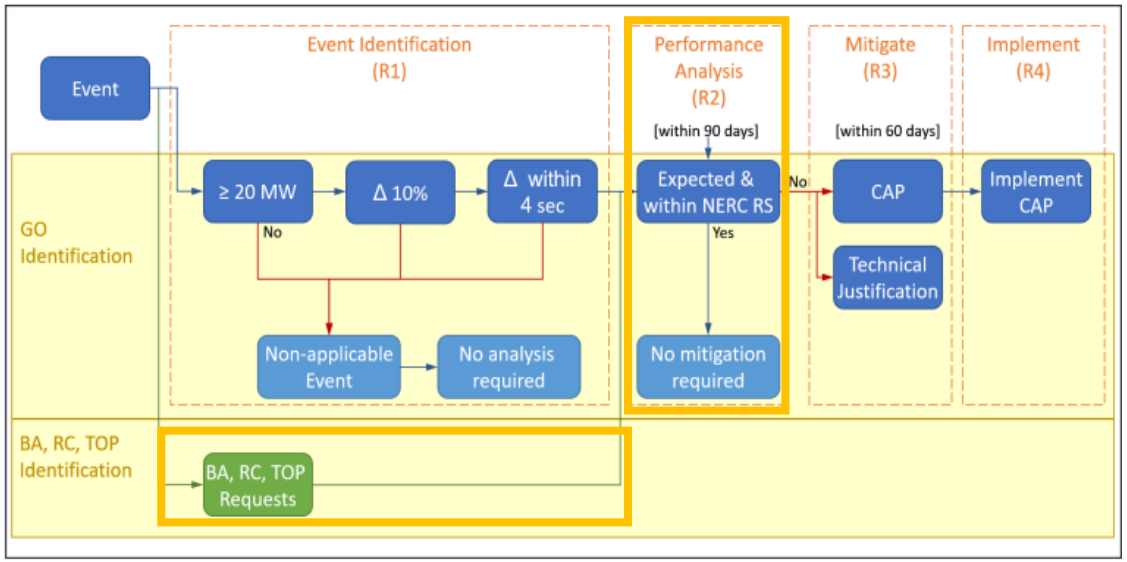
R1. Each applicable Generator Owner shall implement a documented process to identify any complete facility loss of output, or changes in Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period. Changes in Real Power for the following are excluded: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Changes associated with intermittent primary energy source availability, created by changes such as variation in wind speed and solar irradiance;
- Resource dispatch, resource ramping, planned outages, or planned resource testing;
- A Transmission or collection system loss that, by configuration, disconnects the Inverter-Based Resource generator; or
- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

Defines how events are to be identified

Includes exceptions that should not be identified

Requirement R2



Source: PRC-030 Technical Rationale

R2. Each applicable Generator Owner, within 90 calendar days of a Real Power change event pursuant to Requirement R1 or following a request from its associated Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output, shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Analyze its Inverter-Based Resource facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

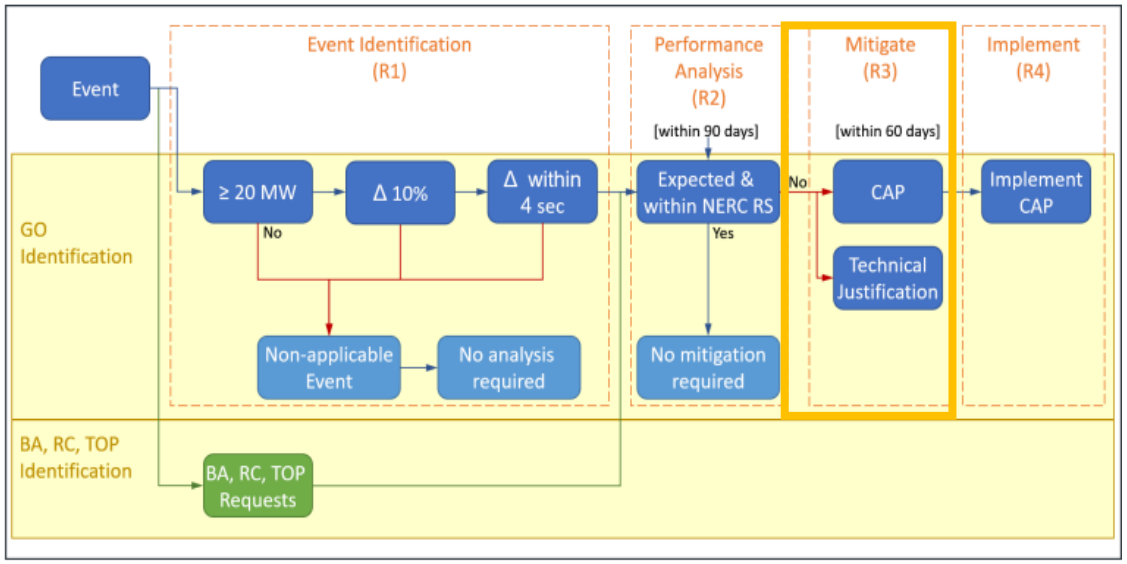
2.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.

Requires analysis of identified events

Includes assessment of specific elements, as described in subparts

Provide data to RC, BA, TOP upon request

Requirement R3



R3. If performance issues and a need for corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the associated Reliability Coordinator, Balancing Authority, and Transmission Operator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

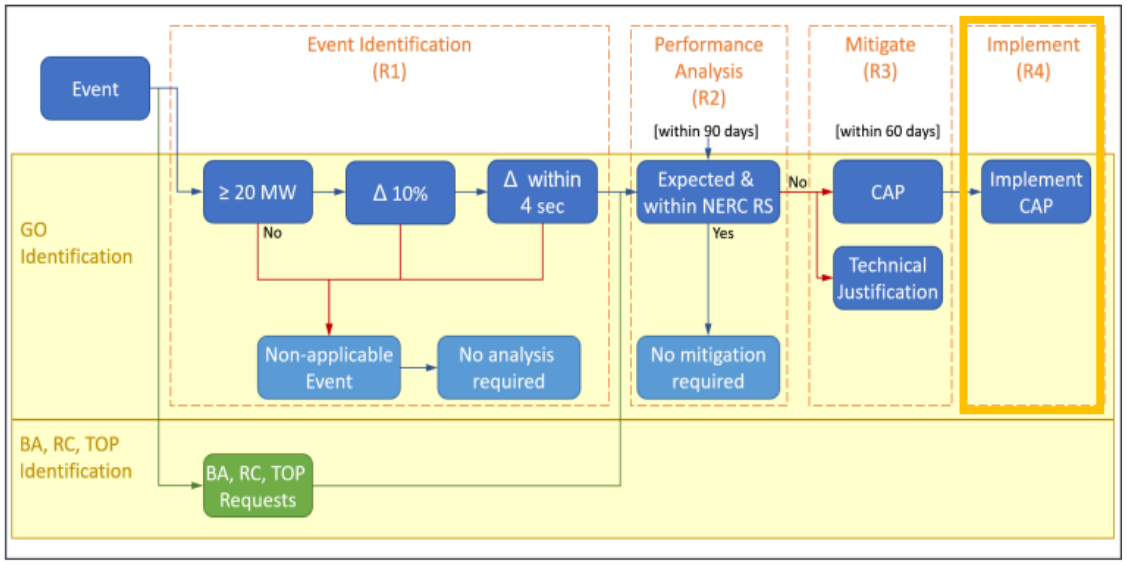
- A Corrective Action Plan (CAP) for the identified Inverter-Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
- A technical justification that addresses why corrective actions will not be implemented.

Source: PRC-030 Technical Rationale

Requires a Corrective Action Plan for identified events

Requires technical justification for not implementing a CAP

Requirement R4



R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- **4.1.** Implement the CAP;
- **4.2.** Update the CAP if actions or timetables change; and
- **4.3.** Notify each associated Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

Source: PRC-030 Technical Rationale

Requires mitigation of the performance risk through CAP implementation

Requires updates and notification for CAP timetable changes and completion

Implementation Plan

BES IBRs

- October 1, 2026

non-BES IBRs

- January 1, 2027

- BES IBRs are higher impact
- Allows entities to focus on assets with greatest reliability impact first
- Accommodates Category 2 registration
- Supports orderly compliance of new registrants

Additional Resources

Project 2023-02

Analysis and Mitigation of BES Inverter-Based Resource Performance Issues

PRC-030-1 Standard

Unexpected Inverter-Based Resource Event Mitigation

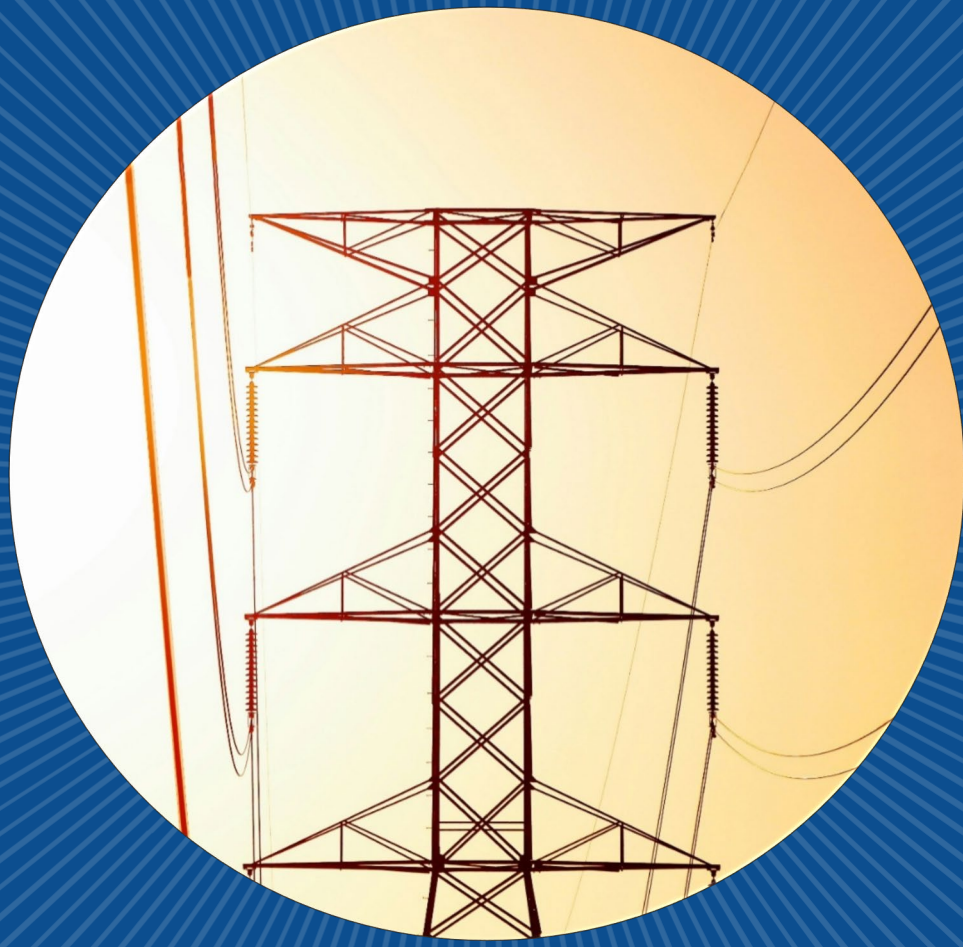
Implementation Plan

Technical Rationale

NPCC

TOP-003-7

Transmission Operator and Balancing Authority Data and Information Specification and Collection



NPCC Standards & Criteria

Brian Deckert

March 24, 2026

Upcoming Standards | Public

Background

- Inconsistent output from variable energy resources, coincident with unassured deliverability of fuel supplies and volatility in load, can result in insufficient amounts of energy available from the Bulk Power System (BPS) needed to serve electrical Demand, maintain sufficient Operating Reserve, and ensure the reliable operation of the BPS.
- Many entities started incorporating some version of energy reliability assessments, but independently and with inconsistent methods.
- BAL-007-1 is intended to provide BAs with tools necessary to successfully navigate a system that has both variable loads and resources.
    - The BA may require additional data from other entities for their Near-Term Energy Reliability Assessment. BAL-007-1 does not require other entities to provide necessary data, TOP-003 requires the BA to 'maintain a documented specification for the data necessary for it to perform its analysis functions."

Changes

New Definition

- Near-Term Energy Reliability Assessment
  - An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

R2 & R4

- R2: Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
  - R2.1: A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.
- R4: Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

Effective Date

- Effective October 1, 2026
- No phased implementation

Additional Resources

Project 2022-03

Energy Assurance with Energy-Constrained Resources

TOP-003-7 Standard

Transmission Operator and Balancing Authority Data and Information Specification and Collection

Redline to Last Posted

Implementation Plan

Technical Rationale

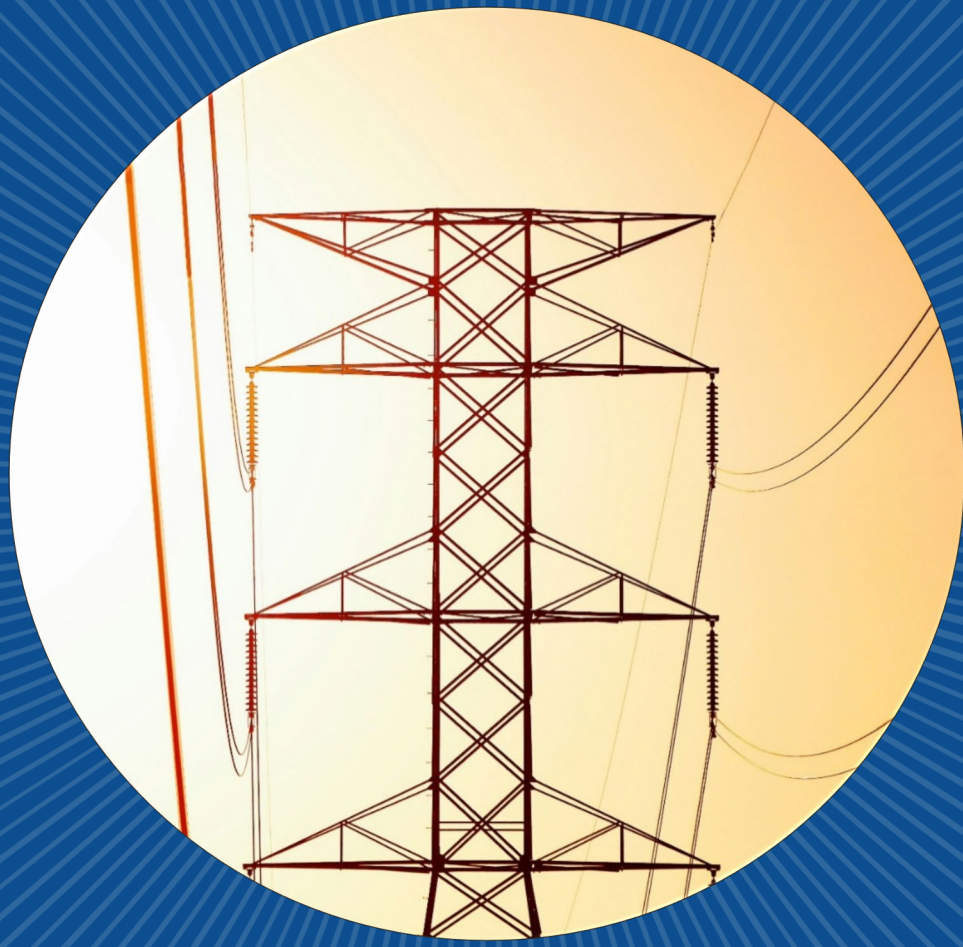
BAL-007-1 Standard

Near-term Energy Reliability Assessments

NPCC

TPL-008-1

Transmission System Planning Performance Requirements for Extreme Temperature Events



NPCC Standards & Criteria

Patrick Davis

March 24, 2026

Upcoming Standards | Public

FERC Order No. 896

Benchmarking

- Develop benchmark planning cases
- Base on extreme heat and cold weather events
- Account for prior major extreme events

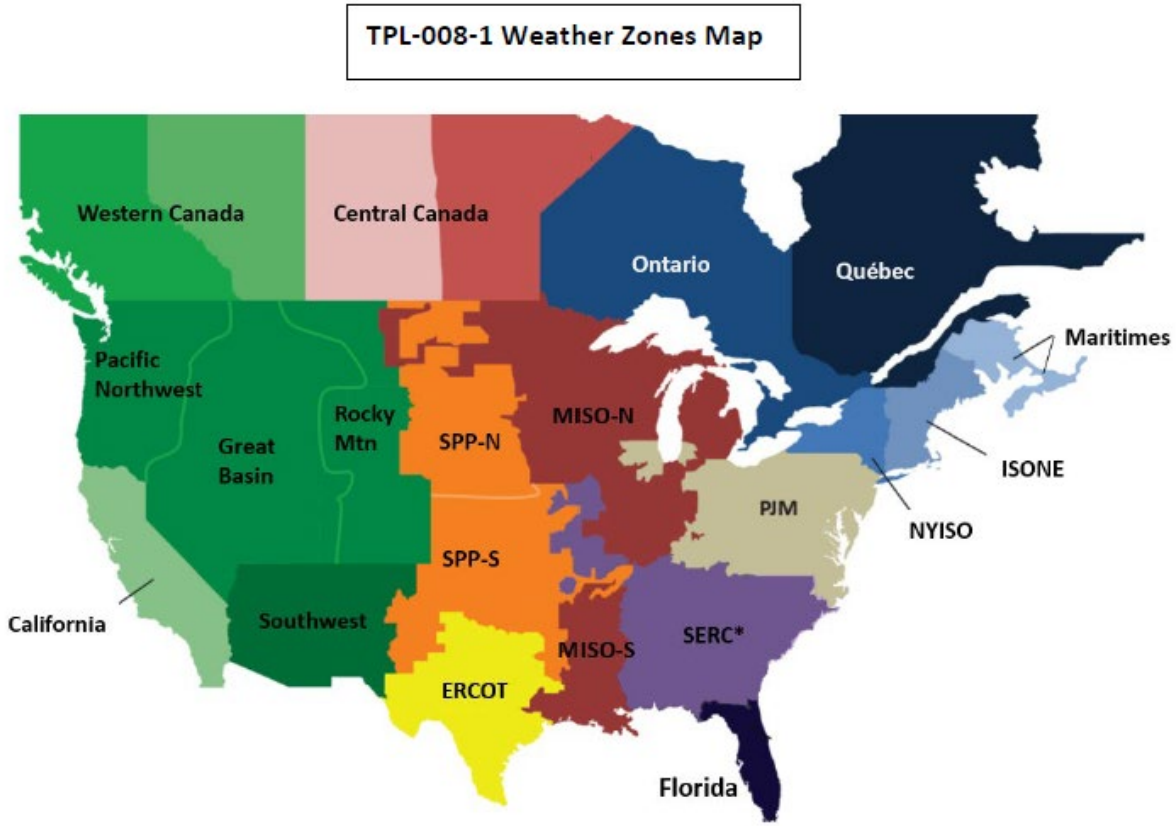
Planning

- Steady state and transient analyses
- Expanded beyond TPL-001 base case
- Cover a range of extreme weather scenarios
- Account for resource mix availability
- Include wide-area impacts

Corrective Action

- Identify instances of concern
- Develop Corrective Action Plan(s)

Extreme Temperature Assessment



ERO Benchmark Event Library

New Definition

- Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

Two Critical Pieces

- Select extreme temperature events in the PC zone
- Coordinate development of models for selected events with all PCs in the zone

Requirements

Requirement R1

PCs and TPs coordinate responsibilities for Requirements R4 thru R11

Once every 5 years

Requirement R2

PC responsibility

Identify pertinent zone(s) from Attachment 1

Coordinate identification of common extreme benchmark temperature events

Requirement R3

PC responsibility

Implement process for developing benchmark planning and sensitivity cases

Requirements

Category	Initial Condition	Event[1]	Fault Type[3]	Contingency BES Level
P0 No Contingency	Normal System	None	N/A	N/A
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[2] 4. Shunt Device[4]	3Ø	≥ 200 kV
		5. Single Pole of a DC line	SLG	
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure[5] 2. Loss of a bipolar DC line	SLG	≥ 200 kV

Source: TPL-008-1

Requirement R4

- Use of MOD-032 data, supplemented by other sources as needed
- Develop benchmark extreme temperature planning and sensitivity cases
- Uses common extreme heat and cold events identified in R2

Requirements R5 and R6

- Criteria for steady state voltage limits and post Contingency voltage deviations
- Define and document criteria or methodology

Requirement R7

- Identifying Contingencies for Evaluation

Requirement R8

- Perform steady state and transient stability analyses
- Uses benchmark and sensitivity cases identified in R4

Requirements

Requirement R9

Develop Corrective Action Plans

Required when a benchmark planning case fails to meet P0 or P1 performance requirements

Requirement R10

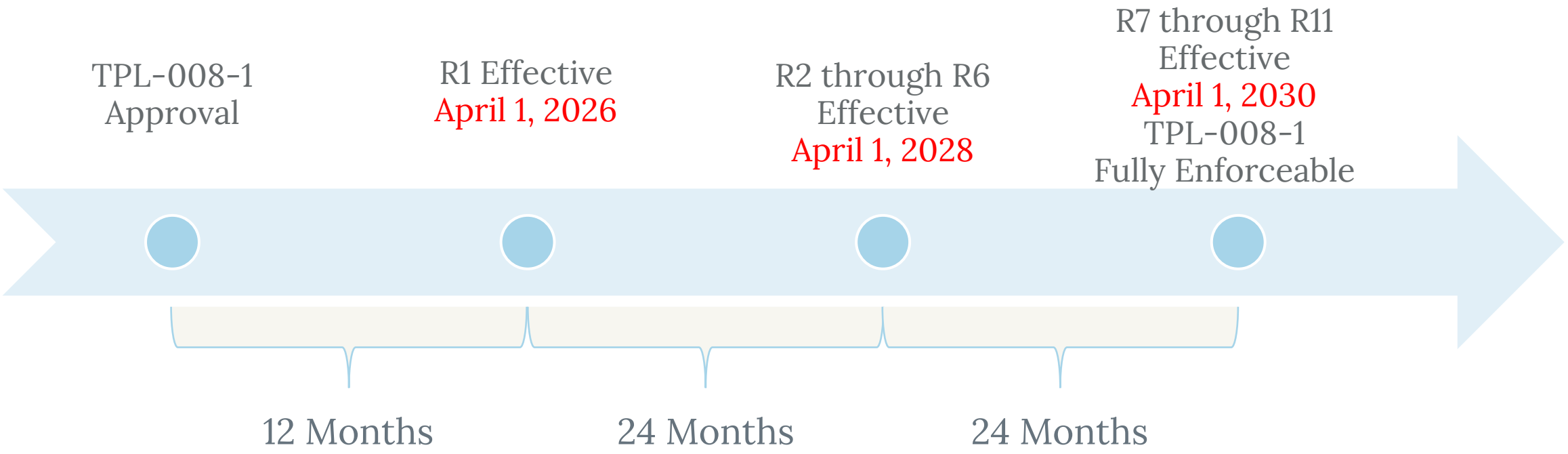
Evaluating and documenting possible actions for performance deficiencies that do not require Corrective Action Plans

Required for P7 Contingencies in benchmark planning cases and P0, P1, and P7 sensitivity cases when deficient

Requirement 11

Provide study results to any functional entity, regulator, or government entity that has a reliability related need

Implementation Plan



Additional Resources

Project 2023-07

Transmission System Planning Performance Requirements for Extreme Weather

TPL-008-1 Standard

Transmission System Planning Performance Requirements for Extreme Temperature Events

Implementation Plan

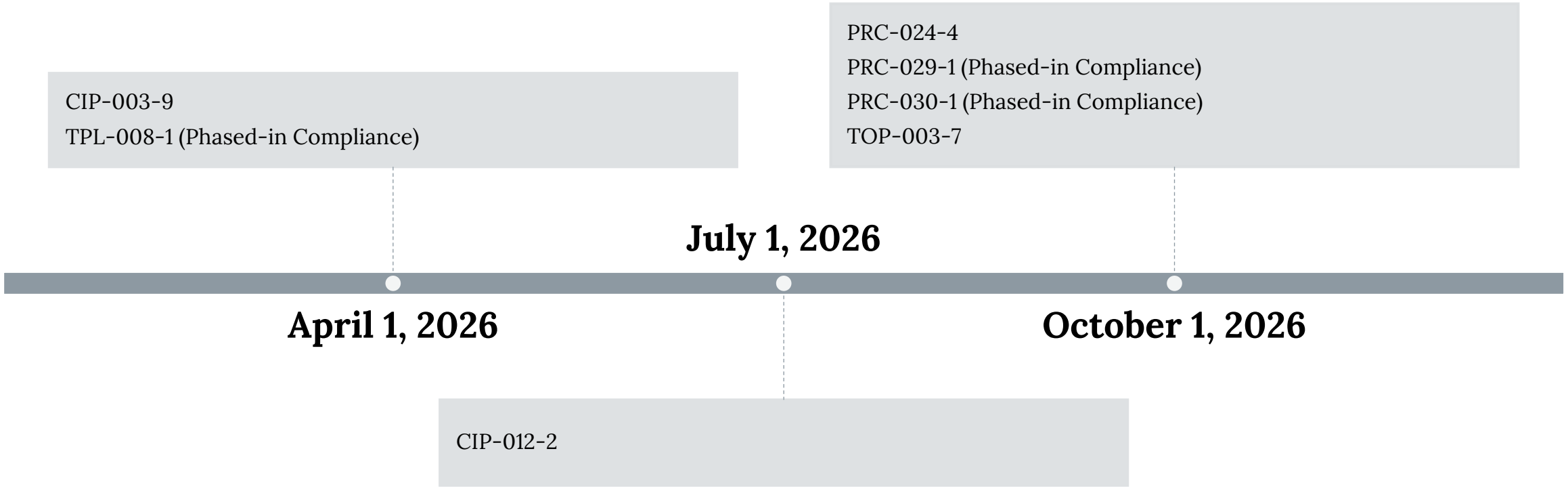
Technical Rationale

ERO Benchmark Event Library

TPL-008 Data Library Read Me

RSAW

Summary


CIP-003-9
TPL-008-1 (Phased-in Compliance)
PRC-024-4
PRC-029-1 (Phased-in Compliance)
PRC-030-1 (Phased-in Compliance)
TOP-003-7
July 1, 2026
April 1, 2026
October 1, 2026
CIP-012-2

NPCC

Questions?

Contact Us: npcc.org/contact

NPCC Standards & Criteria

Upcoming NPCC Events

Reliability Forum	• March 26, 2026 • 9:00 am – 12:00 pm • Register
NPCC Spring Compliance and Reliability Webinar	• May 20, 2026 • 9:00 am – 12:00 pm • Registration Link coming
NPCC Fall 2026 Hybrid Compliance and Reliability Conference	• November 4 - 5, 2026 • Venue: Newport Marriott Hotel & Spa Newport, RI • Registration Link coming