NERC

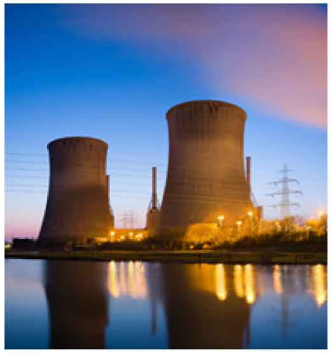
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Industry Webinar

NERC Project 2023-06: CIP-014 Risk Assessment Refinement

October 17, 2024

RELIABILITY | ACCOUNTABILITY

Agenda

- Presenters
  - Drafting Team
    - Chair, Karl Perman, CIP Corps.
    - Vice Chair, Patrick Quinn, Great River Energy
    - Drafting Team Member, Mina Turner, American Electric Power
  - NERC Staff
    - Ben Wu (Project Developer)
- Administrative Items
- Project Status and Background
- Initial Ballot Comments
- Proposed Draft 2 Revisions of CIP-014-4
- Technical Rationale & Implementation Plan Revisions
- Next Steps
- Questions and Answers

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- For the official record
  - This presentation is not a part of the official project record.
  - Comments must be submitted during the formal posting.
- Q&A Session
  - Q/A feature or the raise hand feature.

Drafting Team (DT)

Name	Organization/ Company
Karl Perman (Chair)	CIP Corps
Patrick Quinn (Vice Chair)	Great River Energy
Per-Anders Lof	National Grid
Qamar Arsalan	Public Service Electric & Gas
David Schooley	Exelon
Joel Rogers	SERC Reliability Corporation
Kirpal Bahra	Hydro One Networks Inc.
Bart White	Duke Energy
Mina Turner	American Electric Power

Project Status

- The initial posting was posted from May 20, 2024 through July 3, 2024.
- The drafting team received a lot of comments from the industry.
- The drafting team met 13 times from July 9, 2024 through August 28, 2024, including a three-day in person meeting, to go over the comments and revise the Standard and associated documents.
- The current posting is posted from September 23, 2024 through November 6, 2024.

Background

- Background
  - Due to an increase in reports of physical attacks on electric substations, the Federal Energy Regulatory Commission (FERC) issued an Order on December 15, 2022, in Docket No. RD23-2-000, that directed NERC to conduct a study to evaluate:
    - (1) The adequacy of the Applicability criteria set forth in the Physical Security Reliability Standard CIP-014-3 (Physical Security Reliability Standard);
    - (2) The required risk assessment set forth in the Physical Security Reliability Standard; and
    - (3) Whether a minimum level of physical security protections should be required for all Bulk-Power System transmission stations and substations and primary control centers.
- Purpose/Goal
  - The goal of Project 2023-06 is to identify and physically protect those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS. Registered entity approaches for the risk assessment must be reasonably consistent and substantiated with sufficient technically based rationale.

First Ballot Comments

- Major Themes from First Ballot Comments:
  - Proximity language
  - Fault definition
  - Prescriptiveness of methodology
  - 36-month timeframe usage and alignment

Applicability Section Updates

- Applicability section

4.1. Functional Entities:

4.1.1. Transmission Owner that owns Transmission station(s) or Transmission substation(s) that meet the applicability criteria of Attachment 1.

Requirement R1 Updates and Proposed Language

Updates

- R1 (document applicable facilities)
  - Consolidated sub-requirements into parent requirement
  - Moved "off ramp" from R1 to Applicability section

Proposed Language

R1. Each Transmission Owner, at least once every 36 calendar months, shall document a list of applicable Transmission station(s) and Transmission substation(s) meeting any of the criteria in Attachment 1 that are either existing or planned to be in service within 36 calendar months. *[Violation Risk Factor: High; Time-Horizon: Long-term Planning]*

Requirement R2 Updates and Proposed Language

Updates

- R2 (documented proximity criteria)
  - Sub-requirements are now “and”, not “or”
  - Added “within ½ mile…”

Proposed Language

R2. Each Transmission Owner shall have documented criteria to determine those Transmission station(s) and Transmission substation(s), irrespective of ownership, within ½ mile of an applicable Transmission station or Transmission substation documented in Requirement R1, that could be impacted by a single physical attack. The criteria shall address at a minimum the following: *[Violation Risk Factor: Medium; Time-Horizon: Long-term Planning]*

2.1. Line of sight between multiple Transmission station(s) or Transmission substation(s) from a single location without obstruction.

2.2. Ease of access from a common roadway that exists between multiple Transmission station(s) or Transmission substation(s).

Requirement R3 Updates and Proposed Language

Updates

- R3 (risk assessment methodology)
  - Moved 3.1.1. list of reliability metrics to Technical Rationale
  - More flexible requirements around case choice
  - Removed reference to specific fault types (three-phase or single-line-ground)

Requirement R3 Updates and Proposed Language Cont…

Proposed Language

R3. Each Transmission Owner shall have a documented risk assessment methodology, including criteria for steady-state and dynamic simulations, for evaluating the loss due to a physical attack of each applicable Transmission station(s) and Transmission substation(s) documented in Requirement R1 and Transmission substation(s) or Transmission station(s) determined to be in proximity per Requirement R2. The methodology shall include, at a minimum, the following: *[Violation Risk Factor: High; Time-Horizon: Long-term Planning]*

3.1. Technically supported thresholds and rationale for determining the amount of acceptable load loss, the amount of acceptable generation loss, post-event response, and any additional considerations recognized as resulting in instability, uncontrolled separation, or Cascading within an Interconnection. The technical rationale shall include:

3.1.1. Steady-state and dynamic system response to events that could lead to load loss, generation loss, and other unacceptable post-event response within an Interconnection.

Requirement R3 Updates and Proposed Language Cont…

3.2. Steady-state and dynamic simulations shall be performed under System conditions that are more likely to contribute to instability, uncontrolled separation, or Cascading within an Interconnection.

3.2.1. The simulations shall include the removal of all Elements that Protection Systems and other controls are expected to automatically disconnect for each event.

3.2.2. If steady-state and dynamic simulations each show acceptable system response but additional Elements trip during the dynamic simulation of an event, then additional steady-state analysis including any tripped Elements from the dynamic simulations shall be conducted.

3.3. For each applicable Transmission station or Transmission substation listed in accordance with Requirement R1, analysis shall include a Fault at the applicable Transmission station or Transmission substation and each Transmission station or Transmission substation identified in accordance with Requirement R2 as being in proximity to the applicable Transmission station or Transmission substation.

3.4. Fault simulations that assume the loss of communication and Protection System at the Transmission station(s) or Transmission substation(s) studied under Requirement R3, Parts 3.2 and 3.3.

3.4.1. Delayed (remote) clearing times shall be used unless otherwise technically substantiated.

3.4.2. Actual or more conservative estimates of clearing times shall be used unless otherwise technically substantiated.

Requirement R4 Updates and Proposed Language

Updates

- R4 (joint ownership/coordination)
  - Clarified that R4 coordination only required for R1-identified substations/stations
  - Removed "every 36 month" requirement

Proposed Language

R4. Each Transmission Owner with applicable Transmission station(s) and Transmission substation(s) per Requirement R1 owned by multiple Transmission Owners shall coordinate with those Transmission Owners to determine and document their individual and joint responsibilities for performing any required risk assessments per Requirement R5. *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

Requirement R5 Updates and Proposed Language

Updates

- R5 (risk assessment)
  - No substantive changes; modified reference to other requirements to add clarity

Proposed Language

R5. At least once every 36 calendar months, each Transmission Owner shall perform a risk assessment to identify Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection, using the methodology established in Requirement R3 including any Transmission station(s) and Transmission substation(s) identified in accordance with documentation established per Requirement R4. *[VRF: High; Time-Horizon: Operations Planning, Long-term Planning]*

5.1. A Transmission station or Transmission substation identified in dynamic or steady-state simulations as causing instability, uncontrolled separation, or Cascading within an Interconnection when rendered inoperable or damaged as a result of a physical attack does not require any additional simulations during the current risk assessment.

5.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R5 risk assessment.

Requirement Updates Since First Ballot Cont…

- R6-R10 (out-of-scope requirements)
  - No changes from first ballot

Attachment 1

Attachment 1 – Applicability Criteria

Applicable Transmission station(s) or Transmission substation(s) are those that meet any of the following criteria:

1. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

   ~~2.1 Transmission station(s) or Transmission substation(s), that individually are not applicable, but are applicable when combined based on physical adjacency per Requirement R2, based on aggregated weighting value criteria from **Table 1** are to be considered as applicable.~~

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

Attachment 1 Cont…

3. Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

Technical Rationale and Implementation Plan

- Technical Rationale
  - Updates to reflect requirement changes
  - Moved reliability metrics from 3.1.1. to TR
- Implementation Plan
  - Added, "The initial risk assessment required by CIP-014-4, Requirement R5, must be completed on or before the effective date of the standard."

Next Steps

- Posting
  - Project Page 2023-06
  - 45-day comment period and formal ballot September 23 – November 6, 2024
- Point of contact
  - Ben Wu, Senior Standards Developer
  - Ben.Wu@nerc.net or call 470-542-6882
- Webinar posting
  - Three business days
  - Standards Bulletin

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Questions and Answers