PJM Compliance Bulletin

CB020 NERC Standards CIP-002 and CIP-014

General

CIP-014-3 requires entities to identify and protect those Transmission stations and Transmission substations, and their associated primary Control Centers, which if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. In similar fashion, PJM performs analysis in support of compliance with CIP-002-5.1a, which requires Responsible Entities to identify and categorize BES Cyber Systems and their associated BES Cyber Assets, taking into consideration Control Centers, Transmission stations and substations, as well as critical system restoration assets and Special Protection Systems.

As the Reliability Coordinator (RC), Planning Coordinator (PC), and Transmission Planner (TP), PJM will fulfill several roles as it relates to CIP-014-3 including providing input into the assessment to identify Transmission facilities by way of analysis to support Applicability 4.1.1.3. PJM may also serve as the third-party reviewer as required in Requirement R2. This Compliance Bulletin describes the process PJM implemented to identify assets that will serve as input to the analysis required in Requirement R1 in addition to discussing the process for coordinating and communicating to the Transmission Owners (TOs) the results of this analysis and for assisting as the third-party reviewer (R2). Additionally, this Compliance Bulletin provides guidance on the process PJM has implemented to identify assets in addition to discussing the process for coordinating and communicating to the Transmission Owners (TO's) and Generation Owners (GO's) the results of this analyses, to support compliance with CIP-002-5.1a.

Background

CIP-002-5.1a Criterion 2.6

Attachment 1 Criterion 2.6 states: "Generation at a single plant location or 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."

PJM is the Reliability Coordinator, Planning Coordinator, and Transmission Planner for its footprint. This criterion establishes that PJM may identify facilities/locations that should be considered medium impact facilities/locations by the entities that own these facilities. To that end, PJM Operations and Planning conducted an analysis to identify contingencies critical to the derivation of the PJM IROLs (PJM IROLs are published in Manual 37 Section 3.1 and are defined in Manual 03 Section 3.8) that is, that are providing data critical to the derivation of the IROL. That analysis yielded a sub-set of contingencies which were decomposed to Transmission and

Generation facility components. Per the standard, PJM expects that these facilities along with the IROL facilities themselves comprise the list of medium impact facilities:

IROL Facilities + Transmission, Generation Contingency Facilities = Criterion 2.6 List

Next Steps for TO's or GO's: 2.6 Facilities should be considered Medium Impact Facilities

CIP-014-3 Applicability Section 4.1.1.3

Applicability 4.1.1.3 states: "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."

PJM is the Reliability Coordinator, Planning Coordinator, and Transmission Planner for its footprint. The requirement in the applicability of CIP-014-3 establishes that PJM may identify Transmission Facilities that the owning entity should use as input to the assessment required by CIP-014-3 Requirement R1. To that end, PJM Operations and Planning conducted a study to identify contingencies critical to the derivation of the PJM IROLs (a list of PJM IROLs are established in Manual 37 Section 3.1 and their facilities are defined in Manual 03 Section 3.8). That study yielded a sub-set of contingencies that were decomposed into their component Transmission facilities. PJM expects that these facilities along with the IROL facilities themselves will comprise the list of Transmission Facilities that the owning entity shall use to perform an initial risk assessment and subsequent risk assessments in accordance with Requirement R1 of CIP-014-3:

IROL Facilities + Transmission Contingency Facilities = CIP-014-3 Applicability 4.1.1.3 List

Next Steps for TOs: Apply analysis in R1 to the 4.1.1.3 List

The analysis that PJM's Operations and Planning groups conducted will be replicated at least every 15 calendar months to support CIP-014-3.

PJM IROLs and Associated Contingencies

PJM establishes a list of reactive and voltage transfer limit facilities that define the PJM transfer interfaces. A list of PJM IROLs are established in Manual 37 Section 3.1 and their facilities are defined in Manual 03 Section 3.8). These transfer limits are listed by Transfer Interface, and consist of an Interface Definition that lists a number of, 345, 500, and/or 765 kV lines. The interface definitions list the substations at each endpoint of the Transmission Facilities as well as the voltage level.

In order to determine which facilities, in addition to the IROL facilities themselves, are considered "critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies", PJM conducted an analysis using historical Real-time congestion and forward looking seasonal studies. The results yielded a sub-set of contingencies that were decomposed into their component Transmission facilities. PJM considers these Facilities (at a single station or substation) critical to the derivation of the IROL.

Transmission facilities identified above should be subjected to additional analysis by the owning entity as required in CIP-014-3 Requirement R1. The equipment meeting the PJM designation under the Applicability Section 4.1.1.3 in CIP-014-3 includes the Transmission Facilities and terminal equipment at the associated substation locations.

CIP-002-5.1a Criterion 2.3 and Criterion 2.9

Attachment 1 Criterion 2.3 states: "Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year."

Attachment 1 Criterion 2.9 states: "Each Special Protection System (SPS), Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable."

PJM is the Reliability Coordinator, Planning Coordinator, and Transmission Planner for its footprint. PJM notifies Generator Owners or Generator Operators if their facility has been designated as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year. PJM established IROLs based on the analysis as defined in Manual 37 Section 3.1. PJM classifies a facility as an IROL facility on the PJM system if wide-area voltage violations occur at transfer levels near the Load Dump thermal limit. The current IROL facilities are a subset of the PJM Transfer Interfaces. SPS/RAS operations can be evaluated to determine their impact on the IROLs.

Discussion

CIP-002-5.1a

To assist the Transmission Owners and Generation Owners in identification of their list of assets in accordance with CIP-002-5.1a Criterion 2.6, a Transmission Owner and Generator Owner should include:

1. The substations that make up the end points for each line listed in the IROL Interface Definitions in Manual 03, Section 3.8
2. The specific Transmission or Generation Facilities that have been determined as "critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies" by PJM Operations Support and Planning by way of the analysis described above to support CIP-002-5.1a Attachment 1- Criterion 2.6.

CIP-014-3

To assist the Transmission Owners in identification of their list of assets that will serve as an input to Requirement R1, a Transmission Owner should include:

1. The substations that make up the end points for each line listed in the IROL Interface Definitions in Manual 03, Section 3.8.
2. The specific Transmission Facilities that have been determined as "critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies" by PJM Operations Support and Planning by way of the analysis described above.

Coordination and Communication Process

CIP-002-5.1a Attachment 1- Criterion 2.6

PJM will coordinate with the NERC-registered Transmission Owners or Generator Owners should they own facilities identified under CIP-002-5.1a Attachment 1- Criterion 2.6 analysis described above. PJM will issue the NERC-registered Transmission Owner or Generator Owner a formal letter containing the specific facilities identified by PJM CIP-002-5.1a Attachment 1- Criterion 2.6. This letter will be issued by the PJM Compliance Division and will be issued every 15 calendar months to support compliance with CIP-002-5.1. PJM will issue this letter to the point of contact identified by the Transmission Owner or Generator Owner. Applicable entities should ensure that they have identified their primary point of contact for this purpose via email addressed to: regional_compliance@pjm.com.

CIP-014-3 Applicability 4.1.1.3 – Input to Requirement R1

PJM will coordinate with its member Transmission Owners should they own facilities identified under CIP-014-3 Applicability Section 4.1.1.3 analysis described above. PJM will issue the member Transmission Owner a formal letter containing the specific facilities identified by PJM under 4.1.1.3. This letter will be issued by the Compliance Division and will be issued every 15 calendar months to support compliance with CIP-014-3. PJM will issue this letter to the point of contact identified by the Transmission Owner. Transmission owners should ensure that they have identified their primary point of contact for this purpose via email addressed to: regional_compliance@pjm.com.

CIP-014-3 Requirement R2 – Third Party Validation

PJM will also support requests to perform the third party validation as required by CIP-014-3 Requirement R2. To request a third party review please contact NERC.Planning.Coordinator@PJM.com

CIP-002-5.1a Criterion 2.3 and Criterion 2.9

For Criterion 2.3, PJM will support requests to determine whether any generation Facilities within a Transmission Owner's footprint have been designated by PJM as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year. If the Transmission

Owner requests this analysis, PJM will undertake the request on ad-hoc basis. PJM NERC Compliance will coordinate the necessary studies with PJM Transmission Planning and will provide the results to the owner.

For Criterion 2.9, PJM will support requests to determine the impact that an SPS/RAS has on the PJM defined IROLs. If the SPS/RAS owner requests this analysis, PJM will undertake the request on an ad-hoc basis. PJM NERC Compliance will coordinate the necessary studies with PJM Operations and Planning and will provide the results to the owner.

To initiate a CIP-002 Criterion 2.3 generation Facilities analysis request and/or a CIP-002 Criterion 2.9 SPS/RAS analysis request, please contact regional_compliance@pjm.com PJM will provide the results via a secure transfer method.

Conclusion

PJM issued this Compliance Bulletin to coordinate and communicate the processes in place to support compliance with Standards CIP-002-5.1a and CIP-014-3. Should member companies have questions regarding this bulletin or the specifics of the analysis, please contact: NERC.Planning.Coordinator@PJM.com

Appendix 1: PJM Process for CIP-014-3 Compliance

Introduction

The purpose of CIP-014-3 is to identify and protect Transmission stations and Transmission substations, and their associated primary Control Centers, which if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Transmission Owners must first evaluate the criteria listed in the Applicability section for Functional Entities to determine if this Standard is applicable.

Applicability:

- Facilities operating at 500 kV or higher
- 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.

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

- Facility determined, through PJM, to be critical to the derivation of Interconnection Reliability Operating Limits (IROLs).
- Facilities essential to meeting Nuclear Plant Interface Requirements.

PJM Risk Assessment Process and Implementation

To comply with Requirement R1, Transmission Owners must perform a transmission analysis to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. As the unaffiliated third party (Planning Coordinator, Transmission Planner, or Reliability Coordinator), PJM is responsible for verifying the Transmission Owner's risk assessment in accordance with Requirement R2.
The CIP-014-3 risk assessment process was implemented on 10/1/2015. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection.

PJM will cycle the risk assessment process every 30 months, to ensure compliance with the timing requirements in CIP-014-3 Requirement R1. Transmission Owners that own facilities identified in CIP-014-3 Requirement R1 in the 2015 analysis will be required to perform a subsequent risk analysis again starting April 1, 2018. Transmission Owners with no facilities identified in the 2015 analysis will be required to perform subsequent risk analysis again starting October 1, 2020.

Upon completion of the Transmission Owner's CIP-014-3 R1 analysis, the first step in PJM's process is to complete the PJM CIP-014-3 R1 Verification form including the list of all Transmission Owner's identified substations under the R1 analysis. This form is to be submitted by October, 1 of the required study year, based on the result of the previous assessment. Working with PJM Transmission Planning, the NERC and Regional Coordination department will track to closure all compliance related obligations.

CIP-014-3 R1 PJM Verification Form

PJM will provide the CIP-014-3 R1 PJM Verification form along with the case to be used for the analysis prior to 10/1 of the study year. This form is to be completed by each TO and submitted along with all other required materials no later than 10/1 of the study year.
The form includes:

- Administrative details such as Name of Entity and NERC ID
- A Table for facilities identified as R1 facilities, including the technical basis by which the facility was identified

Notes:

In addition to listing all CIP-014-3 R1 facilities in the spreadsheet, please provide PJM with the following information:

1) All input files needed to replicate analysis (Case in PSS/E format or RAW, Contingencies, Monitor File, Sub file)
2) Analytical Methodology used (if different than TODO PSWG) and/or any additional assumptions used in analysis including SPS or Operational controls
3) Detailed Analytical Output of analysis
4) Technical Basis options

Please Utilize PJM's secure transfer tool for all submissions of secure data to PJM: https://sftp.pjm.com/

To Request a case from PJM, please fill out the CEII Request form using the link below and include "CIP-014" and the details of what case you are requesting in the "Description of Information Requested" section of the form: https://pjm.com/library/request-access

PJM then has 90 calendar days [from Transmission Owner analysis completion] to complete its review of the analysis performed in identifying the CIP-014-3 R1 facilities, and will notify the Transmission Owner of the findings of this verification.

If the Transmission Owner does not agree with the findings of PJM's verification, they have 60 days from the time PJM completes its review to work with PJM in resolving any differences and finalize the R1 facilities list. This is the final step in the process and will result in completed PJM CIP-014-3 R1 verification form.

For questions/comments please email: NERC.Planning.Coordinator@pjm.com

PJM TODO PSWG Common Risk Assessment Methodology for CIP-014-3

This common risk assessment methodology was developed among the PJM Transmission Owners (TOs) to guide the performance of Transmission station and Transmission substation risk assessments as required by NERC Standard CIP-014-3. Each applicable Transmission station or Transmission substation shall be subject to a set of steady-state and/or dynamics analyses in which the Transmission station or Transmission substation is placed into an outage condition. The results of these analyses will identify Transmission stations and Transmission substations that, if rendered inoperable or damaged, could result in instability, uncontrolled separation, or Cascading within an interconnection.

Variations to the approach described in this document are permitted provided that the TO provides sufficient technical justification and that the selected alternative approach meets the requirements of CIP-014-3 R1.[1]

Case Selection

PJM will recommend and provide steady-state and dynamics Base Cases to be used in this analysis by all TOs wishing to have PJM perform verification of their analysis. These Base Cases will be reflective of planned system conditions and include projects expected to be in service within 24 months. The Base Cases should represent stressful system conditions on the transmission system based on engineering judgment (e.g., summer peak and light load).

Event Modeling

Triggering Events modeled in analyses should include outaged station analysis, defined by single fenced enclosure or close-proximity enclosure, regardless of number of voltages and yards

[1] "The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances." CIP-014-3, Guidelines and Technical Basis, Page 25.

included in that single fenced enclosure or close-proximity enclosure, except where technical justification is provided for alternative outage scenarios. Examples of the types of factors to consider when assessing close proximity are:

- An easy line-of-sight between all of the substation yards from a single site
- An easy access from a common public roadway that exists between all of the substation yards
- The substation yards are in close enough proximity that a single event can impact both substations (e.g., the debris field from an incendiary device set off at one yard will impact the other yard)

For dynamic simulation, TOs shall establish minimum event modeling requirements that consider the nature of the fault (single-phase, three-phase, etc.), the location of the fault, and how the fault will be cleared.

Thermal, Voltage, and Stability Criteria

During performance of the risk assessment, Transmission Facilities shall be monitored for the following thermal, voltage, and stability criteria. The list of monitored Facilities shall include, at a minimum, the TO Zone where the event is occurring and adjacent TO Zones.

Dynamic Tripping Criteria

During the performance of the dynamic analysis, generation will be monitored and tripped for the following conditions:

- Generator Angles/Voltages that demonstrate instability or a sustained oscillatory response.[2]
    - Synchronous Generators that exhibit loss-of-synchronism (angle exceeds 180 degrees).

Steady-state Tripping Criteria

During the performance of the steady-state analysis, the Transmission Facilities described below will be monitored and tripped for the following conditions:

- Facilities exceeding 125% of their emergency thermal rating or 115% of load dump thermal rating as appropriate.
- Generators with voltages below 90% of their nominal voltage.[3]

[2] An acceptable oscillation envelope will demonstrate a positive decay within the appropriate test period (normally 10 to 15 seconds). Refer to PJM Manual 14B.

[3] This provision intended to represent generator undervoltage tripping caused by undervoltage relays (see PRC-024 Attachment 2) or undervoltage dropout of critical auxiliary load that would lead to tripping of the generator. Note that while monitoring the regulated bus is typically more conservative and consistent with PRC-024 Attachment 2, monitoring of generator terminals may be more appropriate for certain plants (e.g., those with critical loads on low-side of GSU).

- Loads with voltages below 85% of their nominal voltage or TO-specific Undervoltage Load Shed (UVLS) thresholds, if applicable.

Analysis

The risk assessment approach, in general, is provided in the following steps for each applicable station/substation:

1. Perform dynamic analysis:
    a. Apply disturbance for Triggering Event
    b. Trip all Generators that are found to violate dynamic tripping criteria above.
        i. If the system is not stable, steady-state analysis is not needed. Proceed directly to the Evaluation section below.
2. Perform steady-state analysis (skip this step if the system is not stable in Step 1):
    a. Initial Event Analysis – Triggering Event plus any additional tripping found during the dynamic analysis performed in Step (1).
    b. Level 1 Tripping Analysis – Includes tripping of any facilities violating steady-state criteria during Initial Event analysis
    c. Level 2 Tripping Analysis – Includes tripping of any facilities violating steady-state criteria during Level 1 analysis
    d. Level 3 Tripping Analysis – Includes tripping of any facilities violating steady-state criteria during Level 2 analysis.

Evaluation

Once all analyses are complete, the results for each Transmission station or Transmission substation shall be evaluated in regard to their effect on the Bulk Electric System (BES). A Transmission station or Transmission substation shall be considered a risk to cause instability, uncontrolled separation, or cascading within an interconnection if the analyses result in any of the following:

- Unresolvable divergence in dynamic or steady-state analysis
    - Confirm that divergence is not due to modeling issues or local pockets
- System instability identified in dynamic analysis including but not limited to voltage collapse, sustained oscillations, and conditions leading to activation of UFLS.
- BES Transmission bus voltages drop below 0.7 p.u. more than 2.5 seconds after fault clearing or TO-specific criteria that defines unacceptable voltage recovery.
- Generation loss exceeds 8,500 MW[4].

[4] Eastern Interconnection Planning Collaborative (EIPC) Technical Committee Frequency Response Working Group 2020 Final Report Public Version, Online: EIPC FRWG 2020 Report

    - This criterion limits the likelihood that the system frequency of the Eastern Interconnection will encroach on UFLS schemes.[5]
- Loss of load of 1000 MW or more.
    - The threshold is intended to restrict the applicability to large-area impacts rather than small-load areas.
    - Includes consequential load loss and tripped load
    - Total loss of load should be considered
- Steady-state violations following three levels of facility trips
    - Includes lines, transformers, and generators
    - Tripped elements should include 69kV and above facilities

CIP-014 NERC CMEP guidance:
[CMEP Practice Guide CIP-014-3]

NERC Reliability Standards
CIP-002-5.1a (http://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-002-5.1a.pdf)
CIP-014-3 (https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-014-3.pdf)

Note: Working with PJM Transmission Planning, the NERC and Regional Coordination department will track to closure all compliance related obligations.

[5] The maximum generation loss limit will be reviewed periodically to determine if changes need to be made due to new information from updated EIPC or PJM studies.

Document Retention

Entities shall retain all evidence of compliance in accordance with the document retention requirement as stated in the applicable NERC or Regional Reliability Standard. If there is no specific data retention requirement, Entities will retain the data for seven years.

Development History

Revision: 5	01/27/2023
SME:	Michael Herman, Sr. Engineer II, Transmission Planning
Author:	Michael Herman, Sr. Engineer II, Transmission Planning Gizella Mali, Sr. Analyst II, NERC Compliance
Reviewers:	PJM Member TO. Notification of the revision was provided at the following PJM committee: TOA-AC.
Approver:	Michael Del Viscio, Sr. Director, Compliance & Reliability Standards
Reason for Change:	Appendix 1: Added “PJM TODO PSWG Common Risk Assessment Methodology for CIP-014-3” section. Throughout document: CIP-014 updated to V3 and replaced standard link for CIP-014-3.

Revision: 4	Date 05/13/2022
SME:	Michael Herman, Sr. Engineer II, Transmission Planning
Author:	Michael Herman, Sr. Engineer II, Transmission Planning Gizella Mali, Sr. Analyst II, NERC Compliance
Reviewers:	Notification of the revision was provided at the following PJM committees: RSCS, PC, TOA-AC
Approver:	Michael Del Viscio, Sr. Director, Compliance & Reliability Standards
Reason for Change:	Appendix 1: Removed the Common Risk Assessment Methodology portion of the document. Member TOs are directed to the CIP-014-2 CMEP Guide for this topic.

Revision: 3	Date 11/16/2021
SME:	Michael Herman, Sr. Engineer II, Transmission Planning Liem Hoang, Sr. Lead Engineer, Transmission Operations
Author:	Elizabeth Davis, Sr. Analyst II, NERC Compliance Gizella Mali, Sr. Analyst II, NERC Compliance
Reviewers:	Tom Foster, Manager, NERC Compliance Aaron Berner, Sr. Manager Transmission Planning Simon Tam, Manager Transmission Operations PJM NERC Compliance Team

	RSCS Members
Approver:	Michael Del Viscio, Sr. Director, PJM Compliance
Reason for Change:	Periodic review. Added CIP-002-5.1a Criterion 2.3 and Criterion 2.9 Throughout the document: 138kV reference removed, Generation and IROL clarification added, PJM M37 reference added, verified and updated hyperlinks, minor errata changes for clarification purposes.

Revision: 2	Date 12/26/2017
Author:	Bradley Hofferkamp - CIP Compliance, Preston Walker, NERC and Regional Coordination, Michael Herman, Transmission Planning, Stanley Sliwa, Transmission Planning
Reviewers:	Mark L. Holman, Manager - NERC and Regional Coordination Department David Souder, Director - Operations Support and Planning Mark Sims, Manager - Transmission Planning Simon Tam, Manager - Transmission Planning
Approver:	Rob Eckenrod, Chief Compliance Officer
Reason for Change:	Revised title to include CIP-002. Updated NERC Standard hyperlinks. Revised dates in PJM Process for CIP-014-2 Compliance.

Revision: 1	Date 10/12/2017
Author:	Bradley Hofferkamp - CIP Compliance, Preston Walker, NERC and Regional Coordination, Michael Herman, Transmission Planning, Stanley Sliwa, Transmission Planning
Reviewers:	Mark L. Holman, Manager - NERC and Regional Coordination Department David Souder, Director - Operations Support and Planning Mark Sims, Manager - Transmission Planning Simon Tam, Manager - Transmission Planning
Approver:	Rob Eckenrod, Chief Compliance Officer

Reason for Change:	Consolidation of CB 020 (CIP 014 compliance), CB 018 (CIP 002 Compliance), and addition of information on the internal CIP 014 analysis.

Revision: 0	Date 8/1/2015
Author:	Stephanie Monzon, Manager - CIP Compliance
Reviewers:	Mark L. Holman, Manager - NERC and Regional Coordination Department David Souder, Director - Operations Support and Planning Mark Sims, Manager - Transmission Planning Simon Tam, Manager - Transmission Planning
Approver:	Thomas Bowe, Executive Director Reliability and Compliance
Reason for Change:	This is a new document.