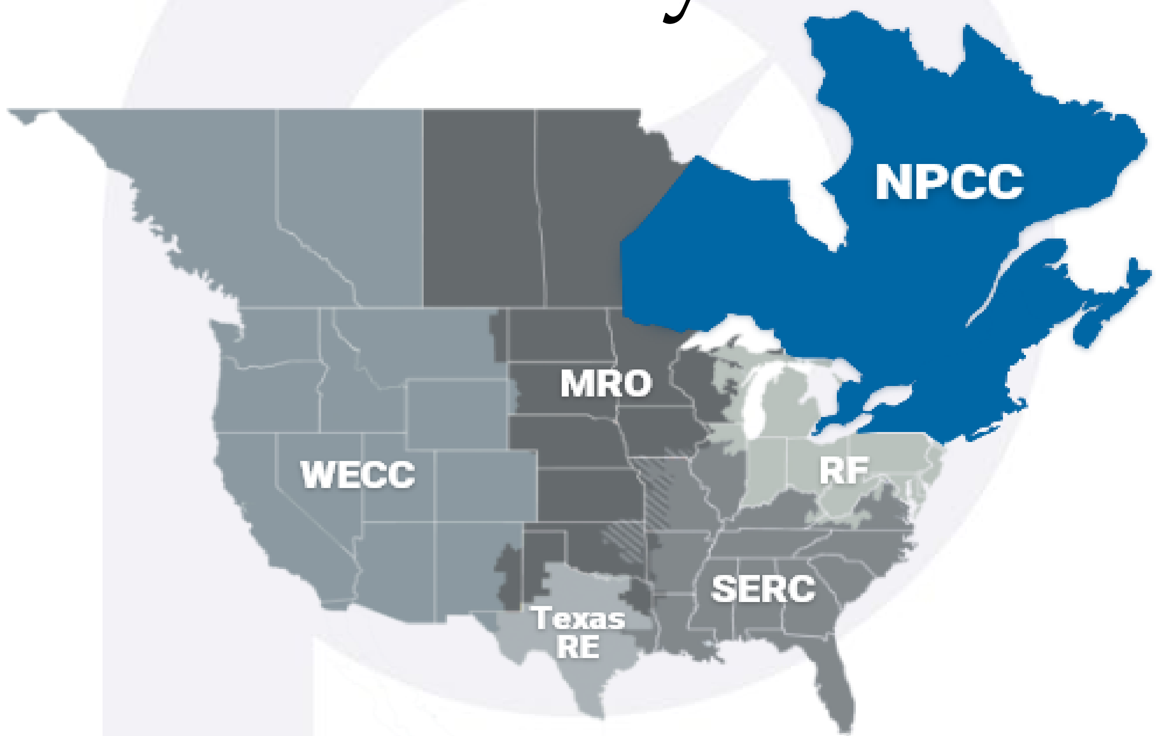
NPCC Spring 2022 Compliance and Reliability Webinar

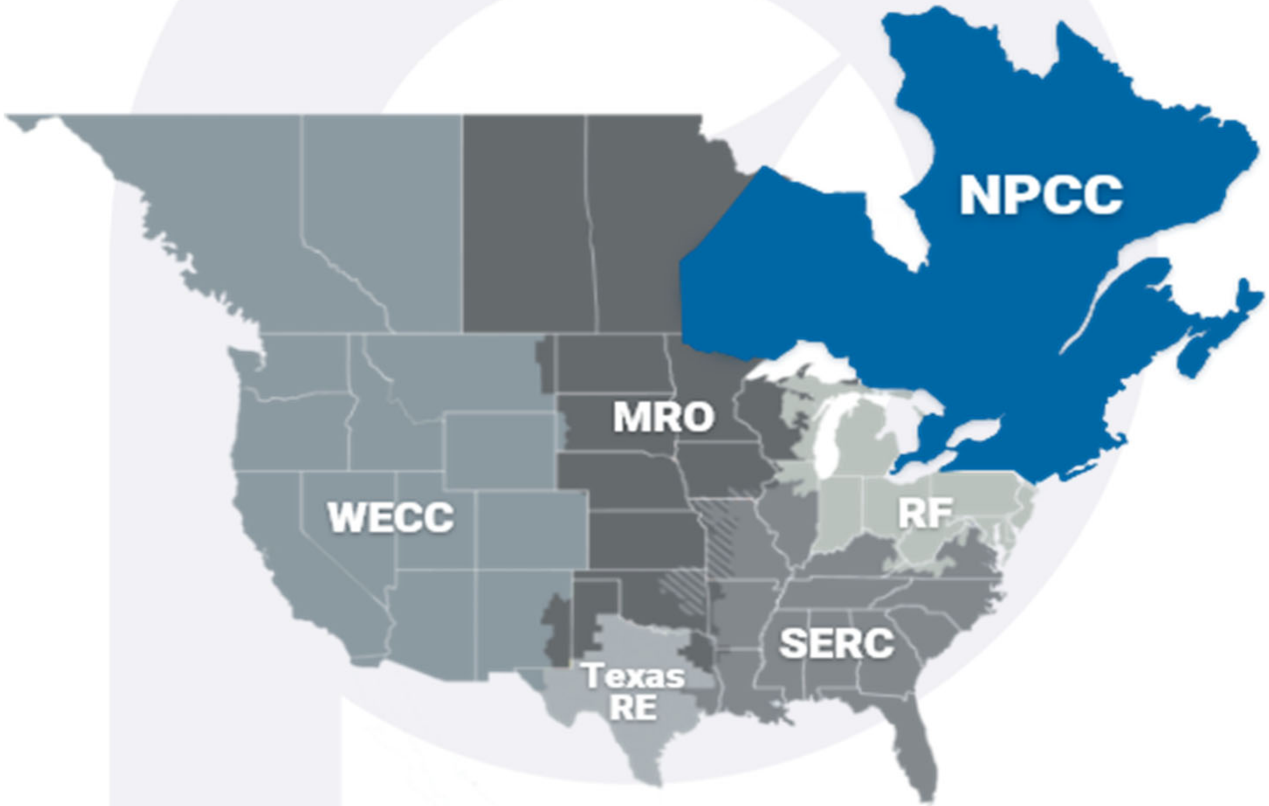


NPCC, Inc.

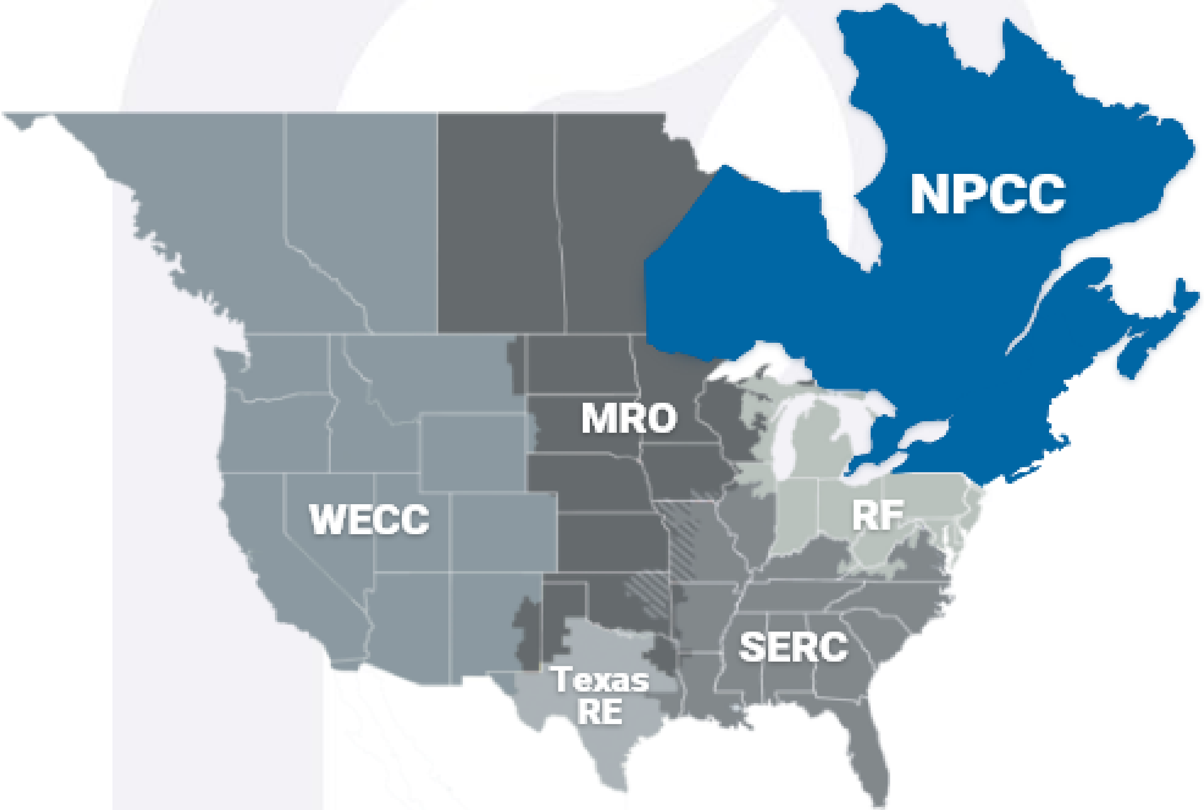
Disclaimer

The information provided today at this workshop is intended to provide accurate and helpful guidance and education to industry and interested stakeholders. The information provided in this workshop is nonbinding and should not be relied upon for compliance or for other matters. The governing documents for compliance and other matters include the applicable NERC Reliability Standard, NERC Rules of Procedure, various regulatory agency orders, approved Implementation guidance and other laws, rules, and regulations. Compliance with Reliability Standards ultimately depends on the facts and circumstances, quality of evidence, and the language of the Reliability Standard.

Safety Message



Opening Remarks
Charles Dickerson
President and CEO



Cold Weather Preparedness Winterization Outreach

May 17, 2022

Matt Forrest

NPCC, Inc.

History

- Southwest Cold Weather Event, February 2011.
- Midwest and Atlantic Seaboard Polar Vortex, January 2014.
- Winter Storm Events, January 2014.
- NE/NY (Northeast Power Pool) Cold Weather event in 1989
- ISONE Cold Weather events in 2004.
- Northeast/North American Ice Storm in 1998
- Many others.

FERC and NERC Responses

- Based on the impact from these events, in 2014, FERC requested that grid operators respond to various questions around their response and follow-up to the events.
- In some areas grid operators created annual winter readiness checks from their generation and transmission entities.
- ERCOT and TRE began performing generating site visits in 2014 to gauge winter readiness and other regions followed.
- Despite the steps taken to attempt to raise awareness and readiness to cold weather events, the Texas/Southwest Cold Weather Event of February 2021 was spread out over 1045 individual BES generating units; 4,124 outages, derates and failure to start up, totaling 34,000 MW of lost generation for two consecutive days. "This is a wake-up call for all of us." FERC Chairman Rich Glick
- In February of 2022, FERC and NERC completed a joint inquiry of the 2021 event which resulted in 29 recommendations and Standards changes to three standards

GO/GOP Standards and Focus Areas

- Cold Weather Standards Enforceable on APRIL 1ST, 2023

- EOP-011-2 Emergency Preparedness and Operations

- *Cold Weather preparedness*
  - *Freeze protection measures, annual inspections and maintenance.*
  - *Limiting conditions – fuel, capacity and availability, fuel switching, environmental constraints, minimum design temperature (operating and shut down), engineering analysis for cold weather performance*
- *Training*
  - *Documented training for operations and maintenance personnel that is generator specific.*

- IRO-010-4 Reliability Coordinator Data Specification and Collection

- *Provide generating unit minimum design temperatures, historical operating temperatures and current cold weather performance analysis to their RC.*

- TOP-003-5 Operational Reliability Data

- *Satisfy the obligations of the documented specifications required for it's balancing authority to perform analysis functions. (Effectively the limiting conditions list from EOP-011-2.*

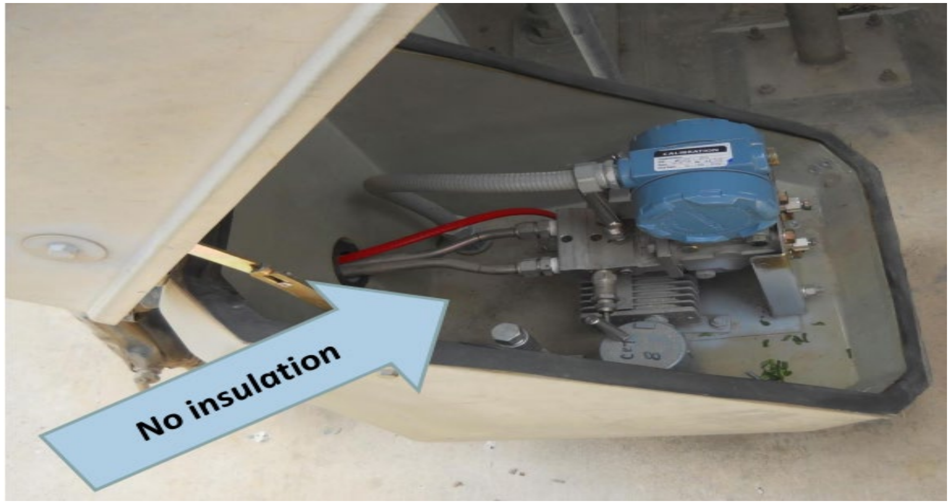
NPCC OUTREACH

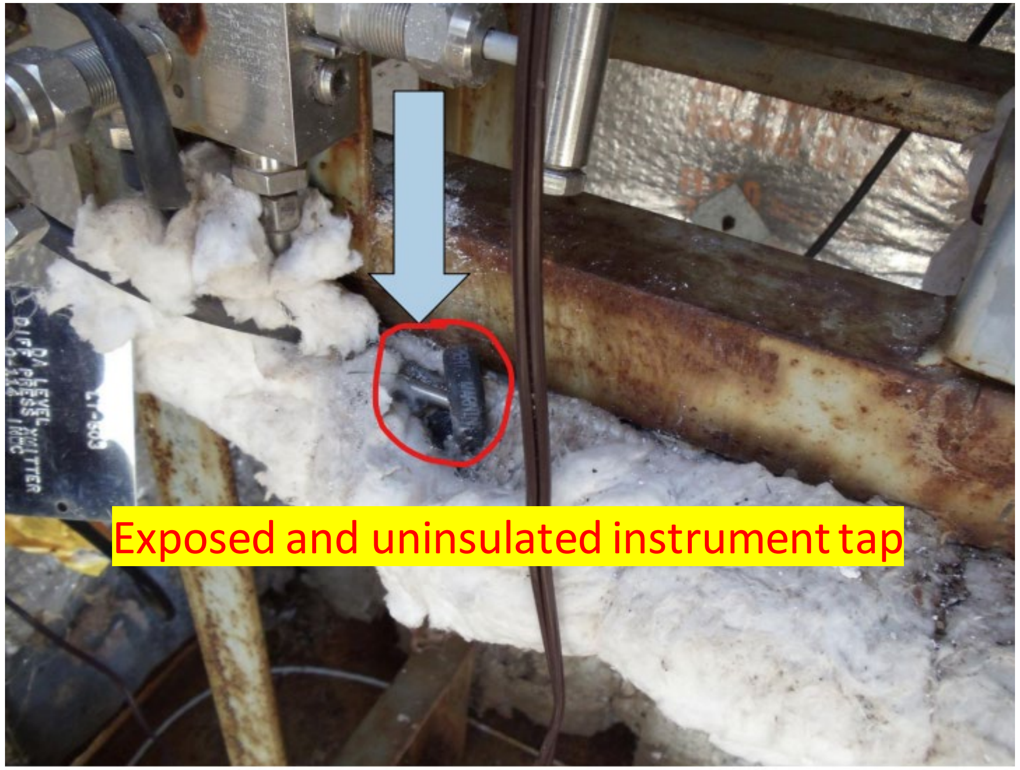
Astoria Energy, LLC
Brookfield White Pine Hydro, LLC
ReEnergy Black River
Cricket Valley Energy Center, LLC
GenOn Bowline
Lockport Energy Associates
Marco DM Holdings, LLC
Mass. Municipal Wholesale Electric Company
Fortistar North Tonawanda
New Athens Generating Company, LLC
Tanner Street Generation, LLC
Canal Generating LLC

- NPCC has invited 12 GO/GOP entities that are on the 2022 audit list to participate in our winter preparedness outreach.
- We have provided each with the GO/GOP self assessment questions from the NERC Cold Weather Practice Guide from October of 2021.
- Reviews of the responses are in progress.
- NPCC will consider up to 3 sites to participate in on-site assessments.
- This is not part of any compliance monitoring process or formal certification

NPCC OUTREACH

- Prior reviews of cold weather events along with site visits have provided several items that should be considered when each entity evaluates their approach to standards compliance.
  - Failed Heat Trace
  - Inoperable steam traps
  - Instrument failures
  - Damaged or missing insulation
  - Damaged doors or other inadequate wind breaks





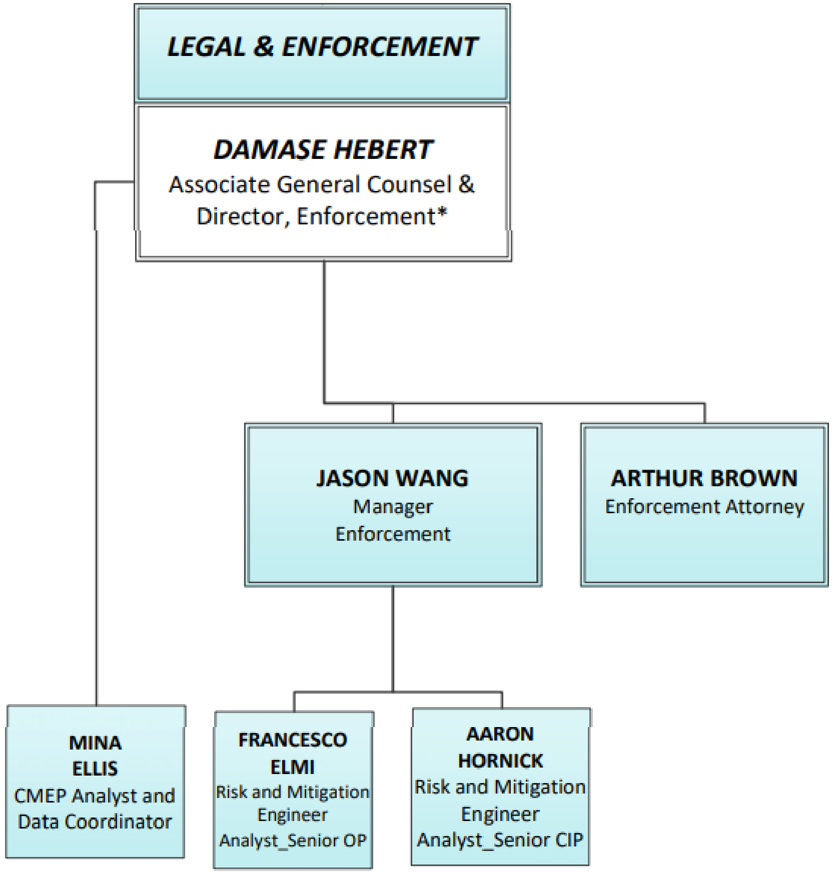
Streamlining Non-Compliance

Jason Wang

Manager of Enforcement and Mitigation

NPCC, Inc.

Who is the Enforcement Team and What does Enforcement Do?

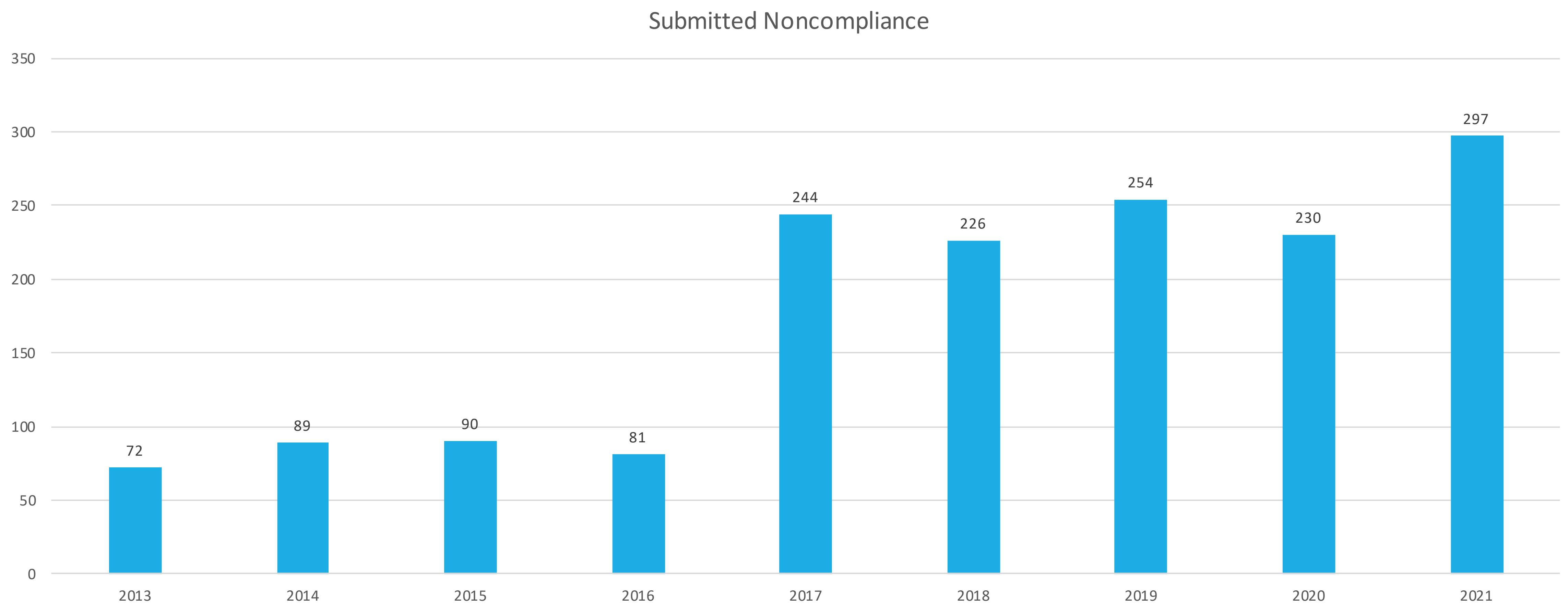


- Compliance Exceptions
- Find, Fix, Track

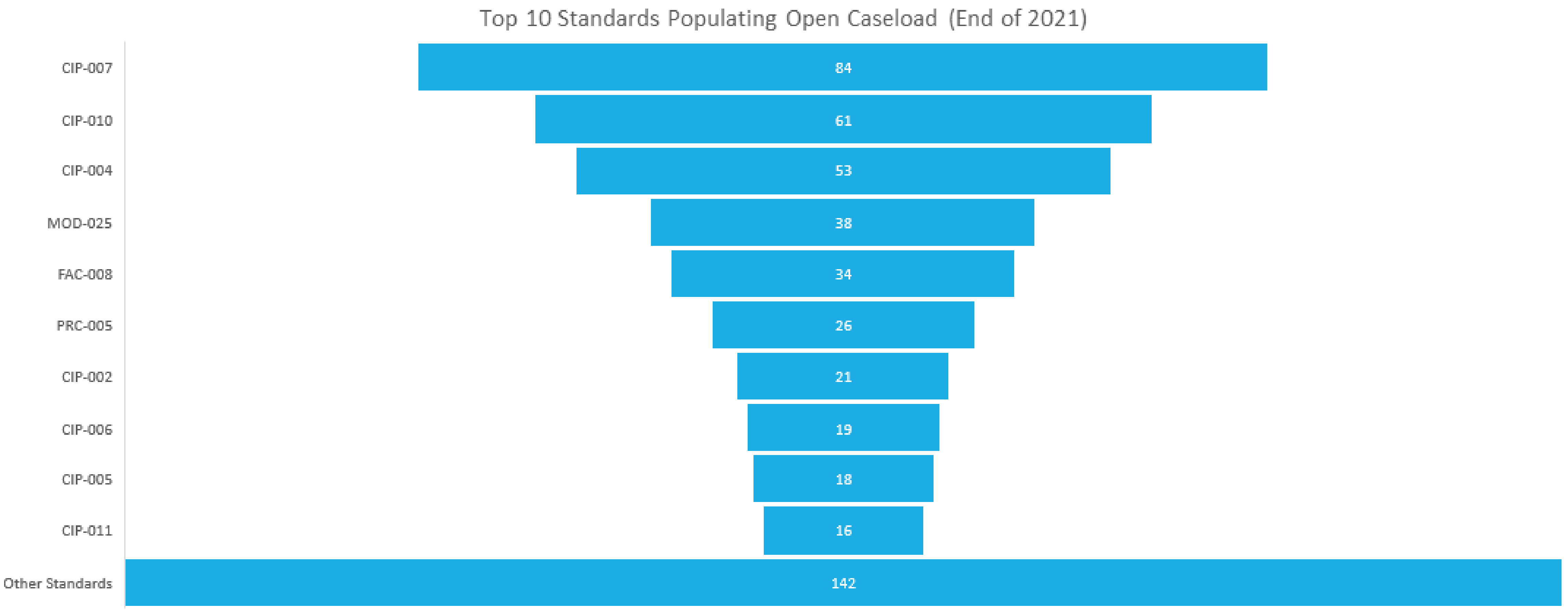
- Spreadsheet Notice of Penalty
- Full Notice of Penalty

- Mitigation

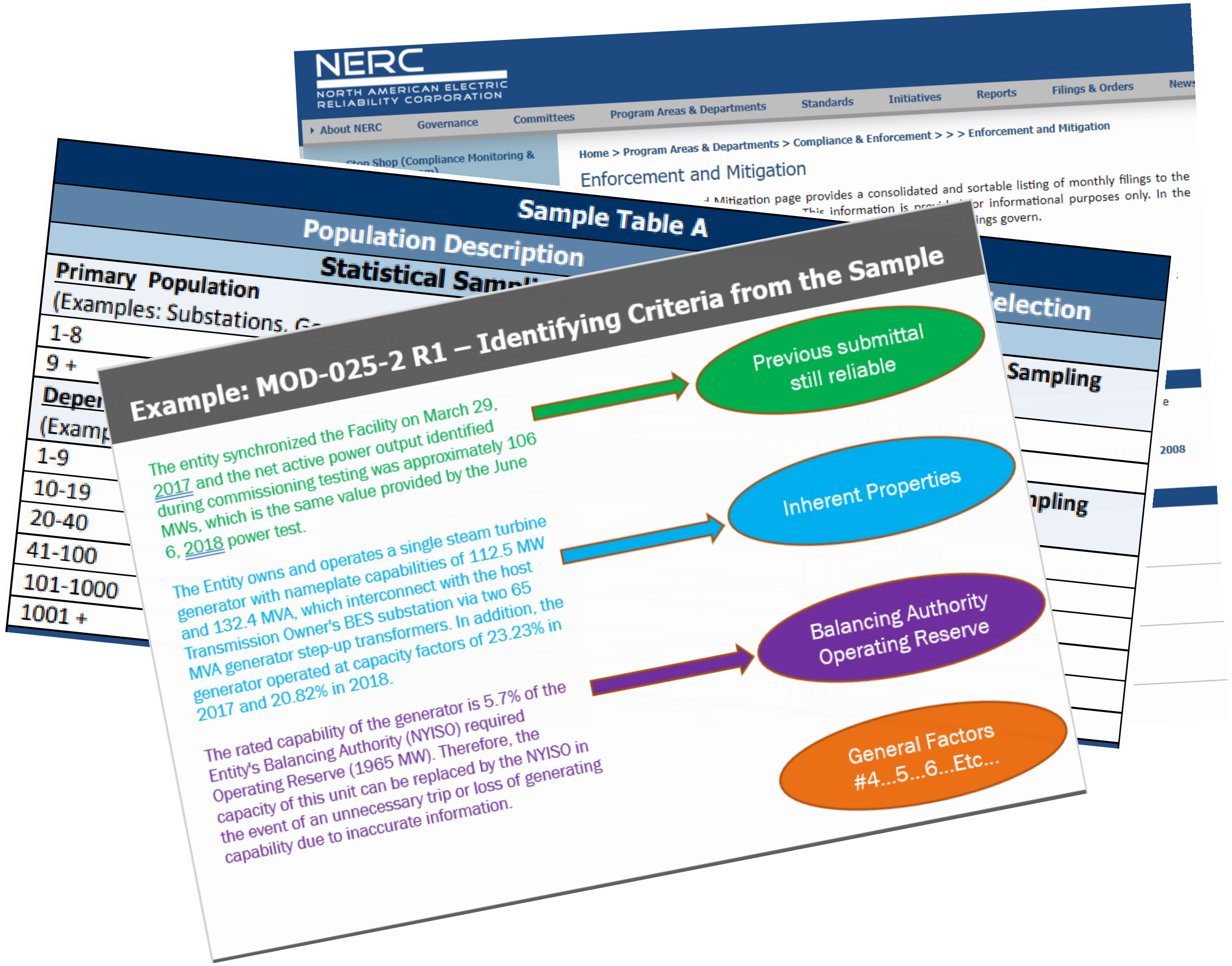
NPCC Enforcement Trends

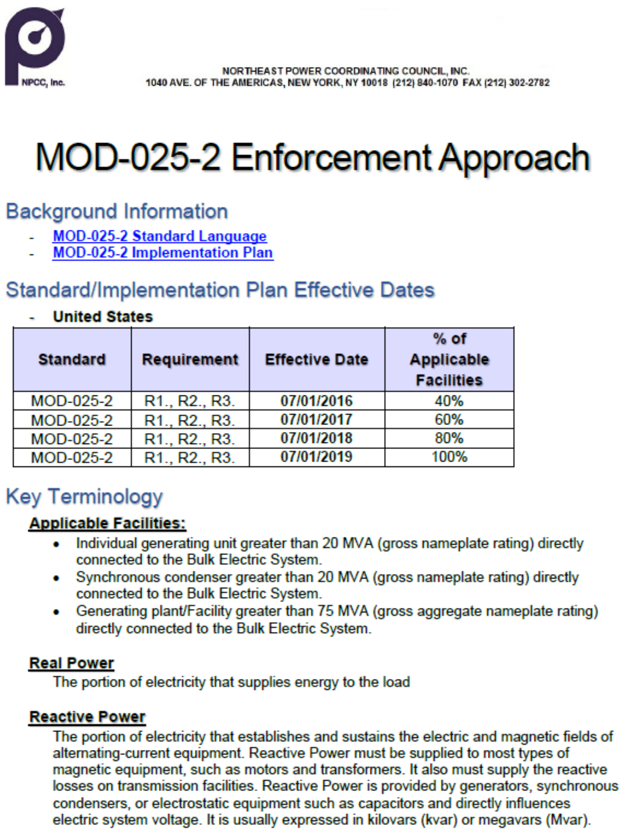


What Are We Doing About It?



How Are We Going To Do It?





NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE. OF THE AMERICAS, NEW YORK, NY 10018 (212) 840-1070 FAX (212) 302-2782

MOD-025-2 Enforcement Approach

Background Information

- MOD-025-2 Standard Language
- MOD-025-2 Implementation Plan

Standard/Implementation Plan Effective Dates

- United States

Standard	Requirement	Effective Date	% of Applicable Facilities
MOD-025-2	R1., R2., R3.	07/01/2016	40%
MOD-025-2	R1., R2., R3.	07/01/2017	60%
MOD-025-2	R1., R2., R3.	07/01/2018	80%
MOD-025-2	R1., R2., R3.	07/01/2019	100%

Key Terminology

Applicable Facilities:

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

Real Power

The portion of electricity that supplies energy to the load

Reactive Power

The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).

Benefits, Current Status and Future Goals

Standard	Enforcement Approach	Applied PNC
MOD-025	Completed	10
CIP-004	Completed	2
PRC-005	Completed	6
CIP-006	Completed	5
FAC-008	In Peer Review (Q2 2022)	N/A
CIP-007	In Progress (Q2 2022)	N/A
CIP-002	Not Started (Q3 2022)	N/A
CIP-010	Not Started (Q3 2022)	N/A
CIP-005	2023	N/A
CIP-011	2023	N/A

2022 Continued Focus
FAC-008 Facility Ratings

Scott Nied
Vice President Compliance
May 17, 2022

NPCC, Inc.

Importance of Facility Ratings

The crux of developing accurate System Operating Limits

Without accurate ratings…

- Real-time situational awareness is impacted
  - Interface MW Flow
  - Transient Stability
  - Voltage Stability
  - System Voltage Limits
  - Interconnection Reliability Operating Limits
- System Operator response during contingencies could make things worse
- Planning studies are inaccurate
- Protection system and relay loadability settings are impacted
- Equipment is damaged

Have been a focus for several years

- April 2021: Recent civil penalty in USA of $42 million
- Issues do not appear to be declining
- What are we seeing in the field?

What have we seen? Rubber on the road examples

Missing components

- Part and pieces and parts that make up the Facility
  - Jumpers and risers inside substations, or possibly a wavetrap
- Missing the identification of Most Limiting Series component

Incorrect ratings on components

- Current Transformers Thermal
- Jumpers/Risers Inside Substations
- Relay Thermal
- Transmission Line Conductor
- Incorrect Aluminum Conductor Stranding
- Disconnect switches

Nuances between Normal, LTE, and STE

Actions by NPCC and NERC

- Discussions at NERC Board of Trustees (BOT)
- FAC-008 is part of 2021/22 Risk Element in NERC Compliance Implementation Plan Training and discussions with NPCC Staff and Regional Staff
- NERC Practice Guide (published 2nd Quarter 2020)
- NERC outreach (workshops, newsletters)
- NERC External Coordination
  - NATF Facilities Ratings Practices Document (for Members)
  - FERC Focus Area during FERC observed audits
  - Facility Ratings Task Force (FRTF) under the NERC BOT

What is the plan?

- ERO Enterprise Facility Ratings Strategy Team
  - ERO internal extent of condition
- Recovery Stage for 2022/23 – Call to Action
  - Continued Communication
  - FAC-008 Monitoring based on impact
  - Examine the current standard

Themes of Root Causes

Lack of Commitment

- Senior Management Engagement and Oversight
- An accurate baseline was never established
- Formalize training and refresh expectations
- Follow an official Corrective Action Program when issues are found

Inadequate Asset and Data Management

- Managing a large amount of components/Facilities
- Lack of facility ratings database with effective data capture and verification and access controls
- Reliance on contractors – oversight and commissioning

Inadequate Change Management Practices

- Establishing and maintaining strong process for communicating change amongst departments
- As-built matches design which matches EMS
- Weak data entry protocols

Best Practices – Robust Programs Include

- A methodology that is annually reviewed with clear instructions and defined roles and responsibilities and obligations by department
- Establishment of an accurate baseline of ratings and equipment
- A mature data management process to ensure continued accuracy
- Annual training for Staff of all involved departments
- Proposed and actual changes are reviewed by Subject Matter Experts
- Required pre-change approvals and notifications
- Periodic reviews/comparisons with internal and external models
- Periodic reviews with others (e.g., construction/maintenance crews, protection and control, Control Center Energy Management System support, coordination with Reliability Coordinator and Transmission Operator, coordination of rating with the neighboring system)
- Process for ad-hoc review for unplanned or if a major event has occurred

Best Practices – Tool and Actions

- Ensure that inventory tools allow write access that is dictated by defined roles in the facility ratings methodology
- Establish automated notifications to affected groups of Facility Ratings changes
  - Protection Engineering
  - Transmission Planning
  - System Operations
  - EMS Support Team
- Validate through periodic field verification of ratings or annually – percentage/quantity determination can be based on legacy, post-event review, and new installations
- Develop a checklist for equipment changes that include:
  - Data provision obligations (internally and externally)
  - Require the need to review impacts to SOLs, protection system settings, EMS/GMS alarming impacts
- Develop a complete Facility Rating database that include all series elements and identifies the most-limiting series element(s) and includes jointly owned Facilities

Aim of NPCC

- Increased entity awareness of this ERO-wide issue
- Reduce risk to the BES
  - Earlier discovery by the entity
  - Corrective and preventative mitigation starts earlier
- Adjustments to entity processes and controls result
- Entity resultant actions lend themselves to being sustainab

<u>If you don't know where you stand, NPCC recommends:</u>

Perform a Self-Assessment

- Full vs. Partial extent of condition

Resources

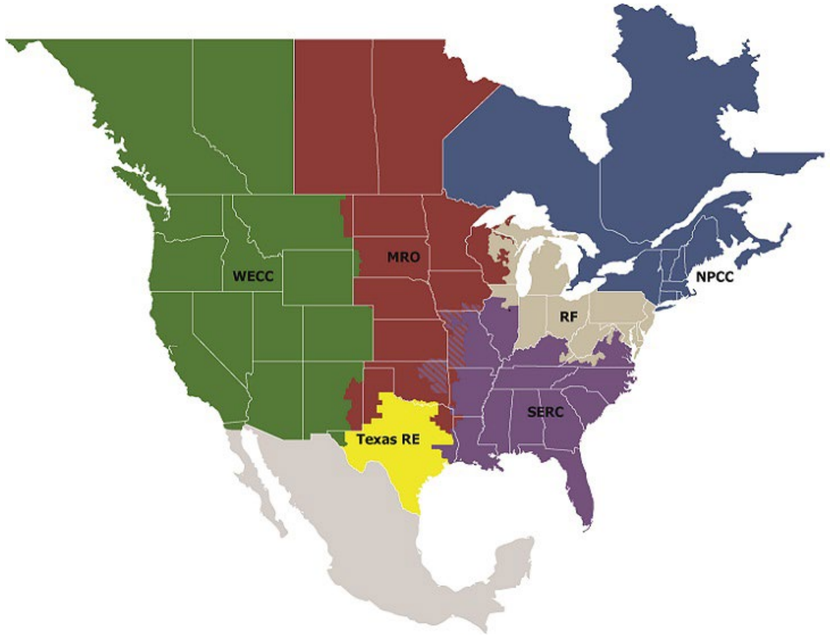
- Help is available!
  - SERC E-Learning module
  - ERO CMEP Practice Guide Facility Ratings
  - ERO CMEP Implementation Guidance FAC-008
  - RF Webinar_April 4_2022_FAC_008
  - Talk With Texas_May 5_2022_FAC-008
- Reach out to NPCC
- Your peers can help too
  - Find like-sized entities with similar challenges
  - What controls do they have?

Thank you for the opportunity and your time!

Scott Nied

snied@npcc.org

Aim of NPCC



Align Update
May 17, 2022

Kimberly Griffith

Senior Compliance Engineer

Dan Kidney

Senior Compliance Engineer

Emily Stuetzle

Senior CIP Analyst

NPCC, Inc.

Align Update

Where We Are
Where We're Going
Training
NPCC Pilot
PDS
Self-Certifications
Wrap-Up

Where We Are

R1 – May 24, 2021
- Self-Reports
- Enforcement
- Mitigations
- Secure Evidence Locker (SEL)

R2 – July 19, 2021
- Self-Certifications
- Periodic Data Submittals
- Technical Feasibility Exceptions

R3 – Live December 2021
- Audits
- Spot Checks
- Investigations/Complains

R3 Enhancements – March 2022

Where We're Going

Release 4 – June 2022

Release 4.5 – October 2022

Data Migration – Goal December 2022

- Schedule
- Audit Must-Haves

- IRAs
- COPs

Training

Release 3

- Initial training sent to PCCs and ACCs via email
- CC Members – Week of May 30
- All Regional Entities – Week of June 6

Release 4/4.5

- CC Members – Week of September 26
- All Regional Entities – Week of October 4

Recordings

Continued Small Group Trainings

Align Audit Pilot

ANL for Off-Site Audit went out April 26

Offering entity targeted training, prior to training in Q2

Feedback

Lessons Learned

Periodic Data Submittals

FAC-003 PDS Requests for Q4 2021 and Q1 2022 completed within Align.

New assignment process for Q1 2022 Request

- Entities required to assign PDS to user for response
- Some minor issues with assigning and viewing questions

99% response rate from NPCC Entities for PDS Requests

Attestations

- Reminder – Simply responding to question that FAC-003 is N/A to your entity will not exclude you from FAC-003 reporting.
- Attestation must be completed and submitted to remove entity from PDS request list
- Attestation require reaffirmation one year after original submittal

Q2 2022 PDS Request will be sent to entities in July.

Self-Certifications

Began using Align for Self-Certifications in Q3 2021

- Evidence submittals in the SEL
- RFIs entered into Align
  - 1 RFI entered for each data request
- Summary Letter and Self-Certification findings entered into Align
  - Areas of Concern
  - Recommendations
  - Positive Observations

Continuing to use Align for 2022 Self-Certifications

Self-Certifications

Lessons Learned - Locker Reference IDs

Evidence

Secure Evidence Locker Reference

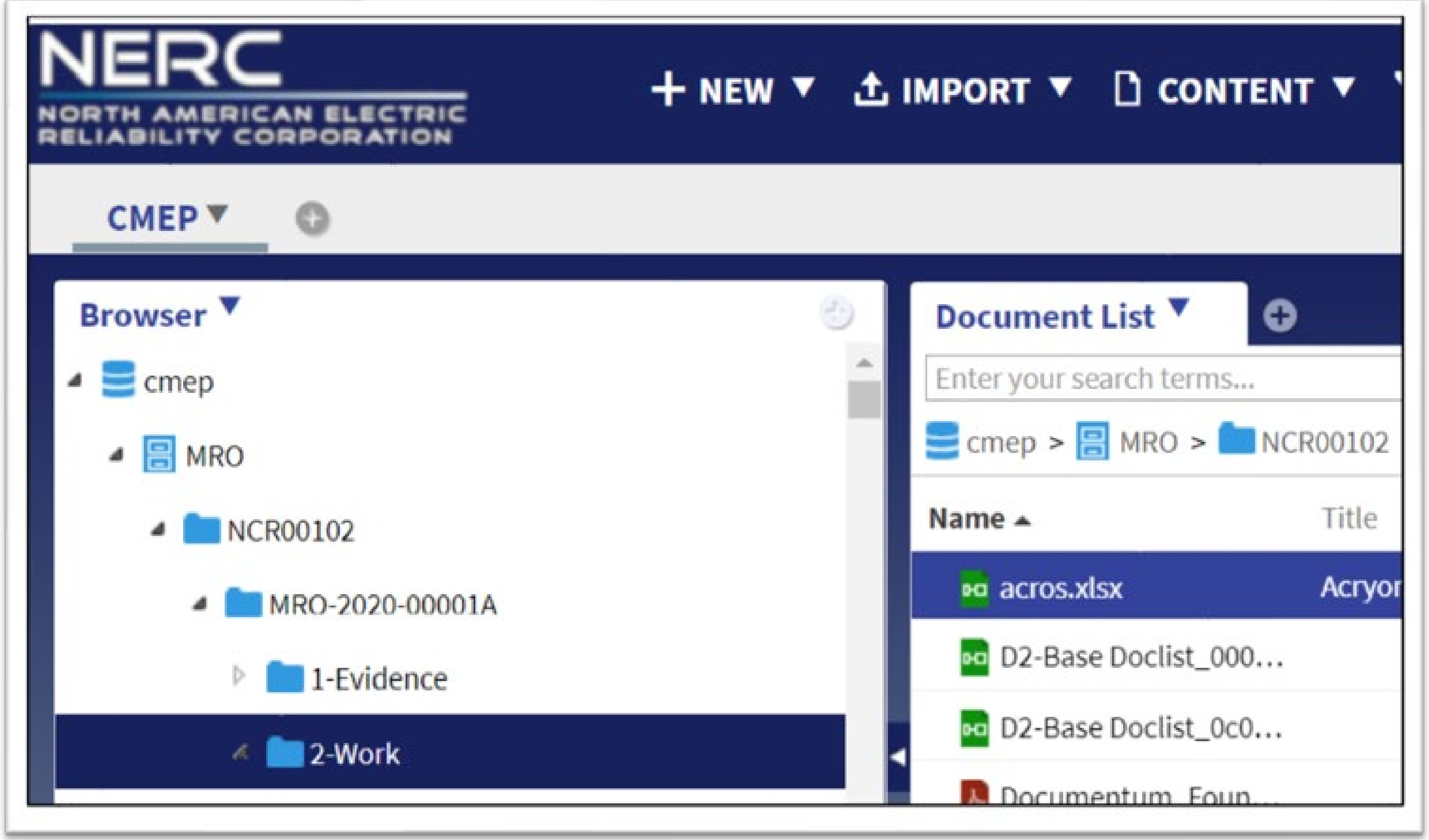
For evidence related to CIP-003-8 R1. use: NPCC|NCR00130|SC2021-000628|SC2021-000628|CIP-003-8 R1.|R1.|
For evidence related to CIP-003-8 R2. use: NPCC|NCR00130|SC2021-000628|SC2021-000628|CIP-003-8 R2.|R2.|

Evidence and Attachments

Locker Reference NPCC|NCR00130|SC2021-000628|SC2021-000628,RF21-000408|||

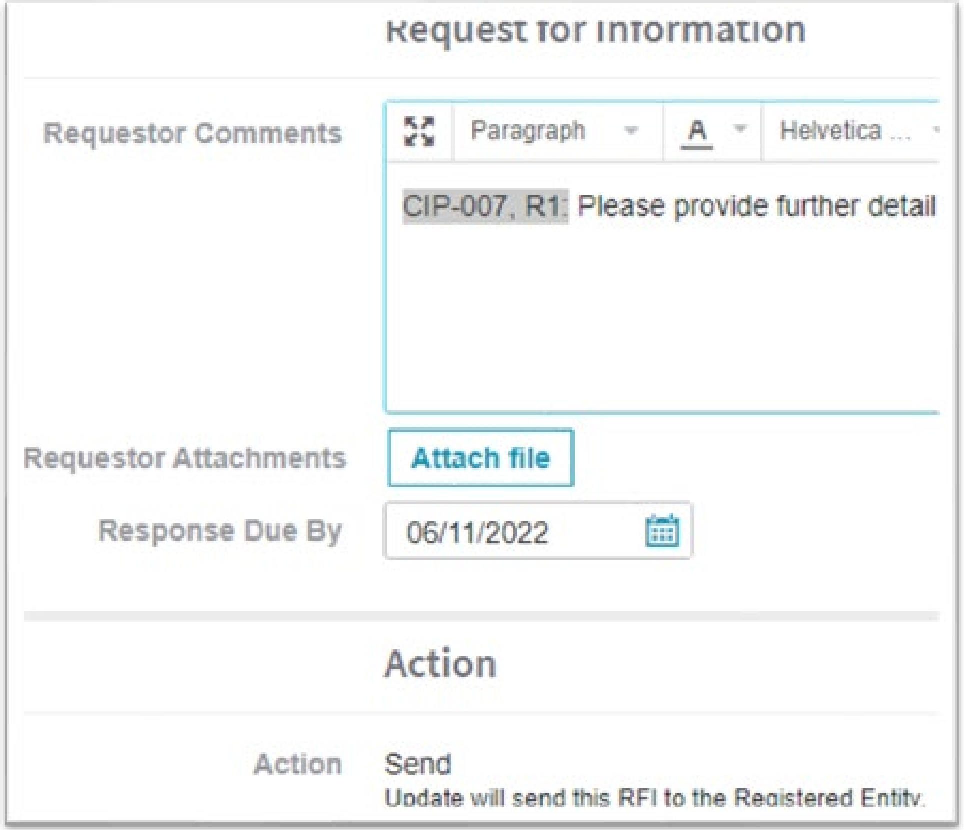
Self-Certifications

Lessons Learned - Filtering in the SEL



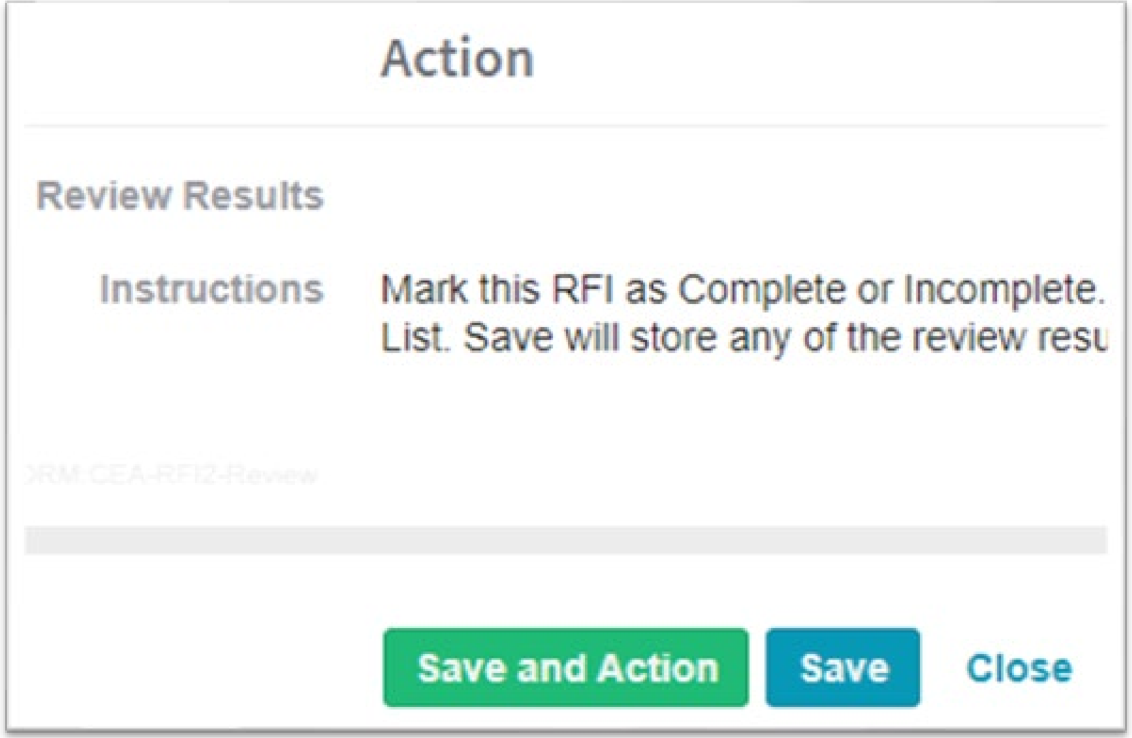
Self-Certifications

Lessons Learned - RFI Standard and Requirement

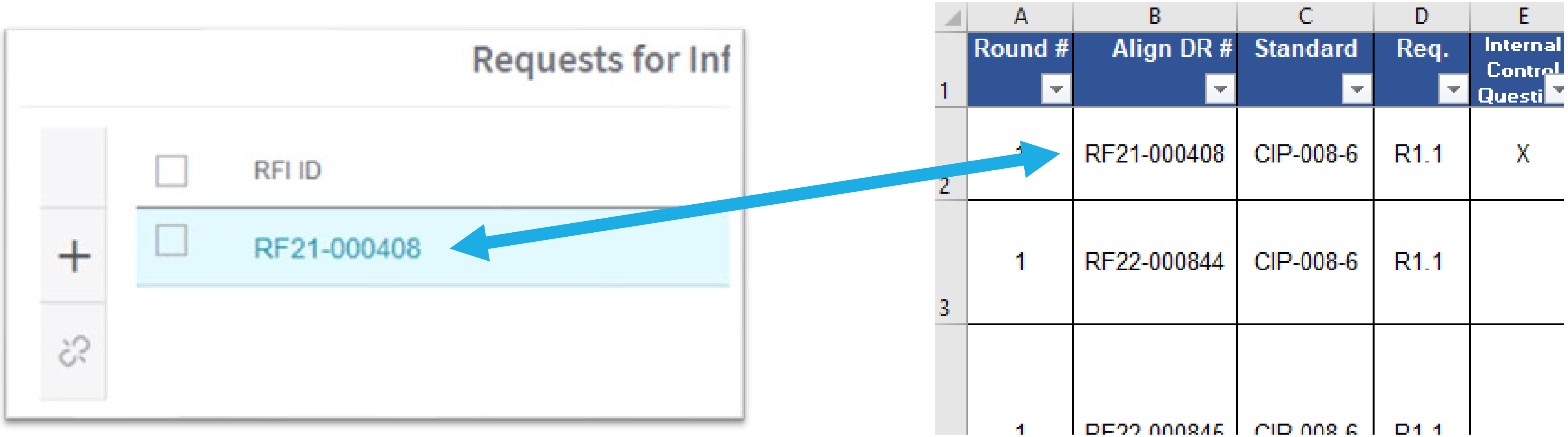


Self-Certifications

Lessons Learned - RFI Close Out



Self-Certifications
Lessons Learned - RFI Tracking



Wrap-Up

Huge and Continuing Effort

- Training Materials
- NPCCAlignTeam@npcc.org
- NERC Align Project Website
- Questions?

PRC Compliance Best Practices and Lessons Learned

Patrick Palompo, PE

Senior Compliance Engineer

NPCC, Inc.

PRC Compliance
Best Practices and Lessons Learned

- PRC-005-6
- PRC-006-NPCC-2

PUBLIC

PRC-005-6

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Protective Relays (Table 1-1)

- **Verify that settings are as specified**
  - Required for microprocessor-based relays (unmonitored/monitored)
  - During testing it is common for some functions of multifunction relays to be enabled/disabled or spare outputs of the relay be temporarily programmed to be used for testing purposes
  - A verification that settings in the relay are as specified should be completed **before the relay is placed back into service**
- **How to show compliance**
  - Dated documentation **at the time of testing** stating that settings were verified to be as specified
    - Examples: Checklists, work orders, maintenance summaries

Table 1-1
Component Type - Protective Relay
Excluding distributed UFLS and distributed UVLS (see Table 3)

Component Attributes	Maximum Maintenance Interval[3]	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

PRC-005-6

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Protective Relays (Table 1-1)

- **Verify operation of the relay inputs and outputs essential to proper functioning of the Protection System**
  - Required for microprocessor-based relays (unmonitored/monitored)
  - All inputs required by the relay for protective functions must be tested (e.g. applying wetting voltage)
  - All outputs utilized by the relay for protective functions must be physically operated (e.g. operate outputs during a test, manually pulse/latch)
  - It is common during relay testing that a spare output of a relay is used for operating feedback to a test set. This method of testing does not verify operation of the designed output contacts of the protection system circuitry.
- **How to show compliance:**
  - Dated documentation **at the time of testing** stating that the operation of the relay inputs and outputs essential to proper functioning of the Protection System have been verified
    - Examples: Checklists, work orders, maintenance summaries

Table 1-1

Component Type - Protective Relay

Excluding distributed UFLS and distributed UVLS (see Table 3)

Component Attributes	Maximum Maintenance Interval[3]	Maintenance Activities
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PRC-005-6

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Using the work of others:

- Many companies utilize third-party contractors to perform PRC-005-6 maintenance work
- The compliance burden will be on the entity
- In your contract, specifically state that you require ***all*** PRC-005-6 maintenance activities be properly documented
  - Do not just state "perform PRC-005-6 maintenance"
  - Provide specific checklists to be completed by third-party contractors
- Review and ***confirm*** that all required maintenance activities were performed and properly documented

PRC-005-6

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Best Practices

- Utilize checklists during PRC-005-6 maintenance work
- Must have dated documentation at the time of testing to show all required maintenance activities were completed

Additional Material

- Supplemental Reference and FAQ documents for clarification of individual maintenance activities listed in the tables
  - PRC-005-6 Supplementary Reference and FAQ
  - https://www.nerc.com/pa/Stand/PRC0056RD/Supplementary_Reference_Rev_2015Oct09_clean.pdf

- ERO Enterprise-Endorsed Implementation Guidance
  - MRO Standards Committee - PRC-005-6 Application Guide
  - https://www.nerc.com/pa/comp/guidance

PRC-006-NPCC-2

Automatic Underfrequency Load Shedding

Requirement 3

Distribution Providers and Transmission Owners

Implement an automatic UFLS program on an island basis specified by Attachment C Table 1 – Table 3

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	6.5 – 7.5	6.5 – 7.5
2	59.3	0.10	0.30	6.5 – 7.5	13.5 – 14.5
3	59.1	0.10	0.30	6.5 – 7.5	20.5 – 21.5
4	58.9	0.10	0.30	6.5 – 7.5	27.5 – 28.5
5	59.5	0.10	10.0	2 - 3	29.5 – 31.5

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

PRC-006-NPCC-2

Automatic Underfrequency Load Shedding

Total Nominal Operating Time

- The time listed should be used as "design criteria"
- No tolerance of +/- 50 milliseconds is specified (Retired NPCC Directory 12 Criteria)

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:

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2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

PRC-006-NPCC-2

Automatic Underfrequency Load Shedding

Total Nominal Operating Time

- Relay time delays should be set low enough to account for the relay operating time, any interposing auxiliary relay operating times, any communication times, and the rated breaker interrupting time
- All factors combined should equal to 0.30 or 10.0 seconds according to the UFLS Tables

UFLS Table 1: Eastern Interconnection

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3	59.1	0.10	0.30	6.5 – 7.5	20.5 – 21.5
4	58.9	0.10	0.30	6.5 – 7.5	27.5 – 28.5
5	59.5	0.10	10.0	2 - 3	29.5 – 31.5

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

PRC-006-NPCC-2
Automatic Underfrequency Load Shedding

Total Nominal Operating Time

Best Practices

- Step 1 - Work backwards to determine what your relay operating time should be
  - Start with your UFLS Stage Total Nominal Operating Time
  - Subtract the rated breaker interrupting time
  - Subtract any communication system times
  - Subtract any interposing auxiliary relay times
  - You'll be left with your relay operating time
- Step 2 – To determine relay time delay settings
  - Start with your relay operating time calculated in Step 1
  - Subtract a known relay processing time and relay output contact closure time as determined from relay testing for your relay model type
  - If the relay underfrequency time delay is programmed in seconds, you'll already be left with your time delay setting
  - If the relay underfrequency time delay is programmed in cycles, you must convert from seconds to cycles based on the frequency of the UFLS Stage you are calculating

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	6.5 – 7.5	6.5 – 7.5
2	59.3	0.10	0.30	6.5 – 7.5	13.5 – 14.5
3	59.1	0.10	0.30	6.5 – 7.5	20.5 – 21.5
4	58.9	0.10	0.30	6.5 – 7.5	27.5 – 28.5
5	59.5	0.10	10.0	2 - 3	29.5 – 31.5

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

PRC-006-NPCC-2

Automatic Underfrequency Load Shedding

Total Nominal Operating Time

- Example 1
  - Stage 1 Relay
  - Relay time delay is programmed in seconds
  - Relay processing time for this type of relay is known based on testing
  - No interposing auxiliary relays in circuit
  - No communication systems used in the circuit
  - Breaker interrupting rated at 5 cycles @ 60 Hz

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	6.5 – 7.5	6.5 – 7.5

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

$$\underbrace{\underset{\text{Relay Setting Time Delay}}{0.187\text{ s}} + \underset{\text{Relay Processing Time}}{0.03\text{ s}}}_{\text{Relay Operating Time}} + \underset{\text{Aux Relay Operating Time}}{0.00\text{ s}} + \underset{\text{Communication Time}}{0.00\text{ s}} + \underset{\text{Rated Breaker Interrupting Time}}{0.083\text{ s}} = \underset{\text{Total Nominal Operating Time}}{0.30\text{ s}}$$

$$5\ cyc \left(\frac{1\ s}{60\ cyc}\right) = 0.083\ s$$

PRC-006-NPCC-2

Automatic Underfrequency Load Shedding

Total Nominal Operating Time

- Example 2
  - Stage 5 Relay
  - Relay time delay is programmed in cycles
  - Relay processing time for this type of relay is known based on testing
  - No interposing auxiliary relays in circuit
  - No communication systems used in the circuit
  - Breaker interrupting rated at 3 cycles @ 60 Hz

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
5	59.5	0.10	10.0	2 - 3	29.5 – 31.5

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

9.92 s + 0.03 s + 0.00 s + 0.00 s + 0.05 s = 10.0 s

Relay Setting Time Delay + Relay Processing Time + Aux Relay Operating Time + Communication Time + Rated Breaker Interrupting Time = Total Nominal Operating Time

$$590\ cyc\left(\frac{1\ s}{59.5\ cyc}\right) = 9.92\ s$$

Relay Operating Time

$$3\ cyc\left(\frac{1\ s}{60\ cyc}\right) = 0.05\ s$$

PUBLIC

PRC-006-NPCC-2

Automatic Underfrequency Load Shedding

Total Nominal Operating Time

- Example 3 **(Potential Noncompliance)**
  - Stage 5 Relay
  - Relay time delay is programmed in cycles
  - Relay processing time for this type of relay is known based on testing
  - No interposing auxiliary relays in circuit
  - No communication systems used in the circuit
  - Breaker interrupting rated at 3 cycles @ 60 Hz

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
5	59.5	0.10	10.0	2 - 3	29.5 – 31.5

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

PNC

10.08 s + 0.03 s + 0.00 s + 0.00 s + 0.05 s = 10.16 s

Relay Setting Time Delay + Relay Processing Time + Aux Relay Operating Time + Communication Time + Rated Breaker Interrupting Time = Total Nominal Operating Time

$$600\ cyc\left(\frac{1\ s}{59.5\ cyc}\right) = 10.08\ s$$

$$3\ cyc\left(\frac{1\ s}{60\ cyc}\right) = 0.05\ s$$

Relay Operating Time

PRC-006-NPCC-2

Automatic Underfrequency Load Shedding

Total Nominal Operating Time

Best Practices

- How to show compliance
  - Your relay setting design approach will be audited to ensure all factors in Footnote 1 are considered as part of the Total Nominal Operating Time
  - Relay settings will be audited to ensure frequency pickups and appropriate time delays are set accordingly to the UFLS Tables

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	6.5 – 7.5	6.5 – 7.5
2	59.3	0.10	0.30	6.5 – 7.5	13.5 – 14.5
3	59.1	0.10	0.30	6.5 – 7.5	20.5 – 21.5
4	58.9	0.10	0.30	6.5 – 7.5	27.5 – 28.5
5	59.5	0.10	10.0	2 - 3	29.5 – 31.5

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

PRC-006-NPCC-2

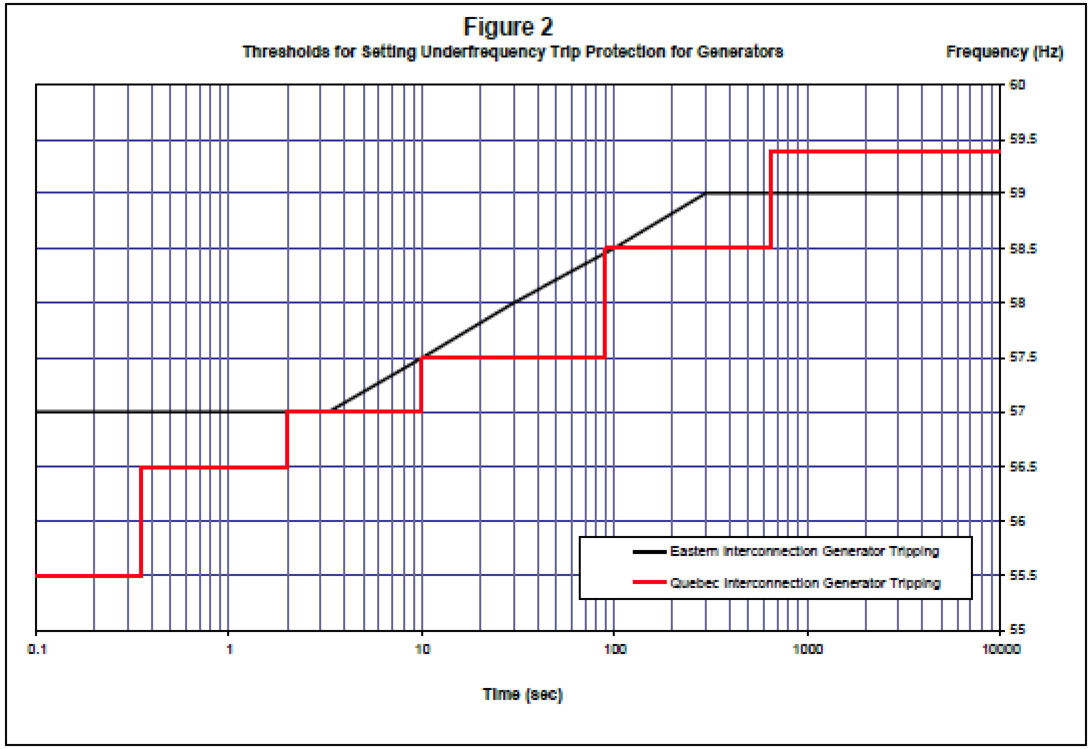
Automatic Underfrequency Load Shedding

Requirement 10

Generator Owners

Set each generator underfrequency trip relay if so equipped, on or below the appropriate generator underfrequency trip protection setting threshold curve in Figure 2, except as otherwise exempted in Requirements R13 and R16

Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators



PRC-006-NPCC-2

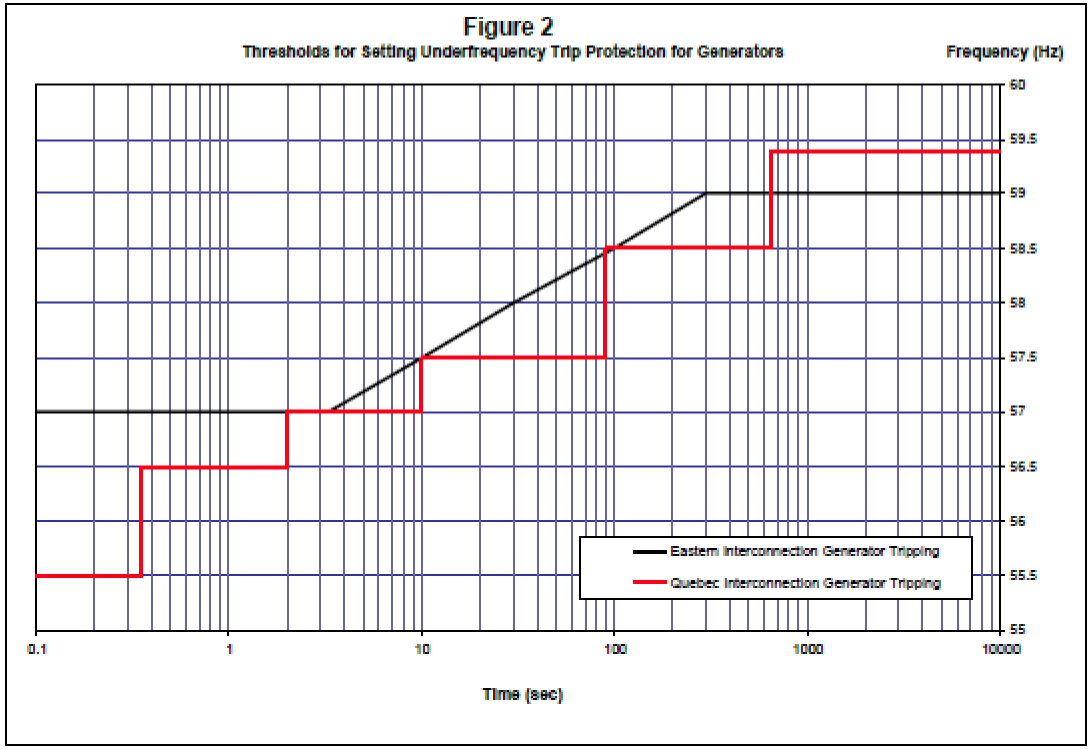
Automatic Underfrequency Load Shedding

Requirement 10

Best Practices

- Review generator step-up transformer protection relays for underfrequency elements
- Review line protection relays for underfrequency elements
- All underfrequency relays, regardless of their specific zone of protection, if enabled and set to trip a generator offline would be in scope of Requirement 10

Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators



Questions?

PRC Compliance Best Practices and Lessons Learned

Patrick Palompo, PE

Senior Compliance Engineer

NPCC, Inc.

CIP-012 Communications Between Control Centers SGAS RECAP

Michael Bilheimer

Senior CIP Analyst

NPCC 2022 Spring Compliance and Reliability Webinar

NPCC, Inc.

CIP-012-1 Is Upon Us!

EFFECTIVE DATE: 7/1/2022

KEY RESOURCES

- ERO Endorsed CIP-012-1 Compliance Guidance
- NPCC Whitepaper on NERC Reliability Standard CIP-012 (Not ERO Endorsed)
- **NERC CIP-012 Small Group Advisory Session Webinar| Presentation| Streaming Webinar**
  - NERC CIP-012 FAQ document (Under Development)
  - CIP-012 RSAW
- **Texas RE 2022 Spring Standards Workshop Presentation| Streaming Webinar**
- **Contact NPCC Compliance: compliance-support@npcc.org**

CIP-012 Goal

Purpose: To protect the confidentiality and integrity of Real-time Assessment and Real-time monitoring data transmitted between Control Centers

NERC Definition: One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of:

- **1) a Reliability Coordinator,**
- **2) a Balancing Authority,**
- **3) a Transmission Operator for transmission Facilities at two or more locations, or**
- **4) a Generator Operator for generation Facilities at two or more location**

Applicability: BA, GO, GOP, RC, TOP, TO

CEC and Exclusions

CEC

- **NERC Glossary of terms**

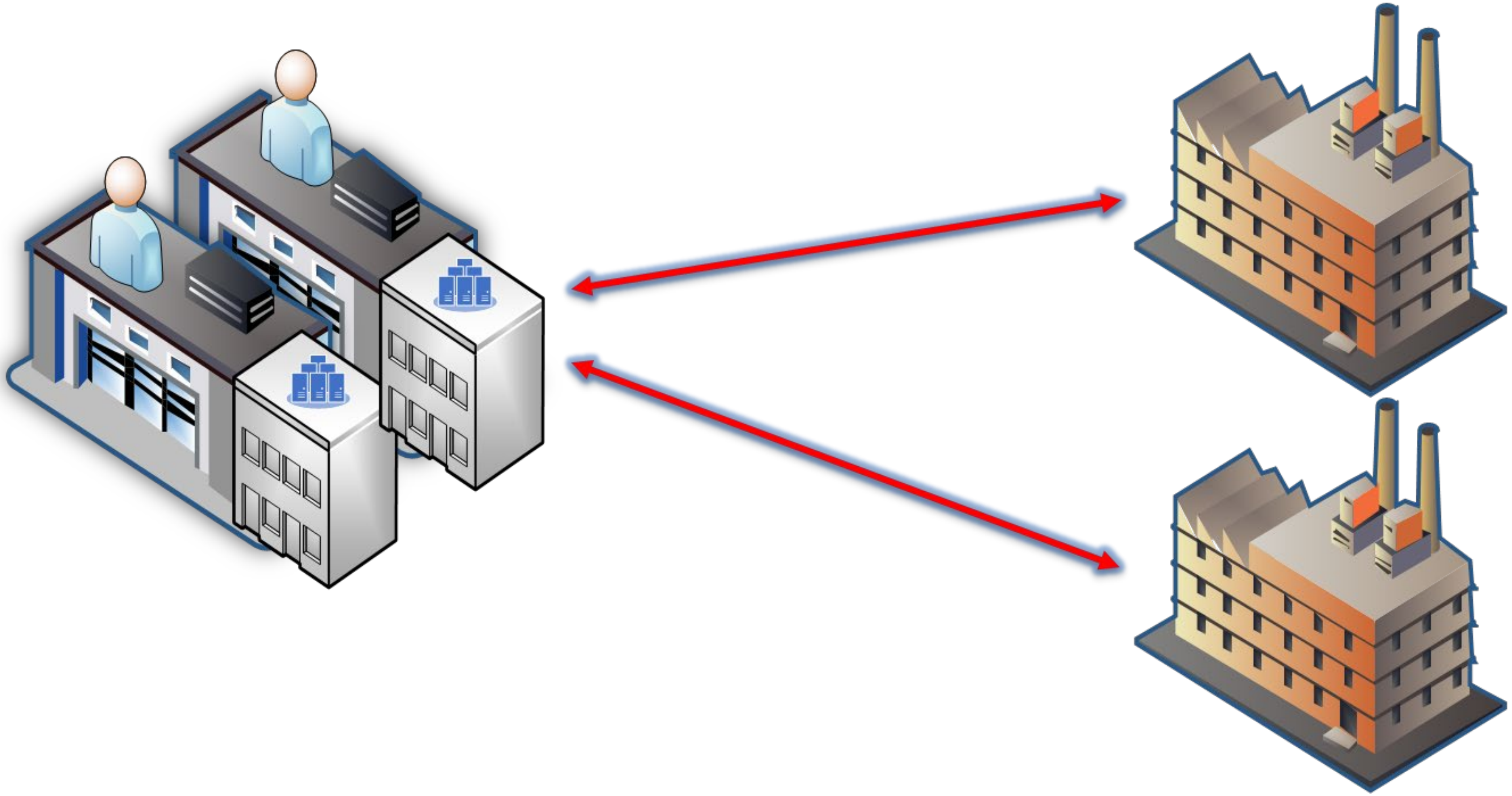
Exclusions

- 4.2.1 Canadian Nuclear Safety Commission.
- 4.2.2 Nuclear Regulatory Commission
- 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.

Protected Communication Communications

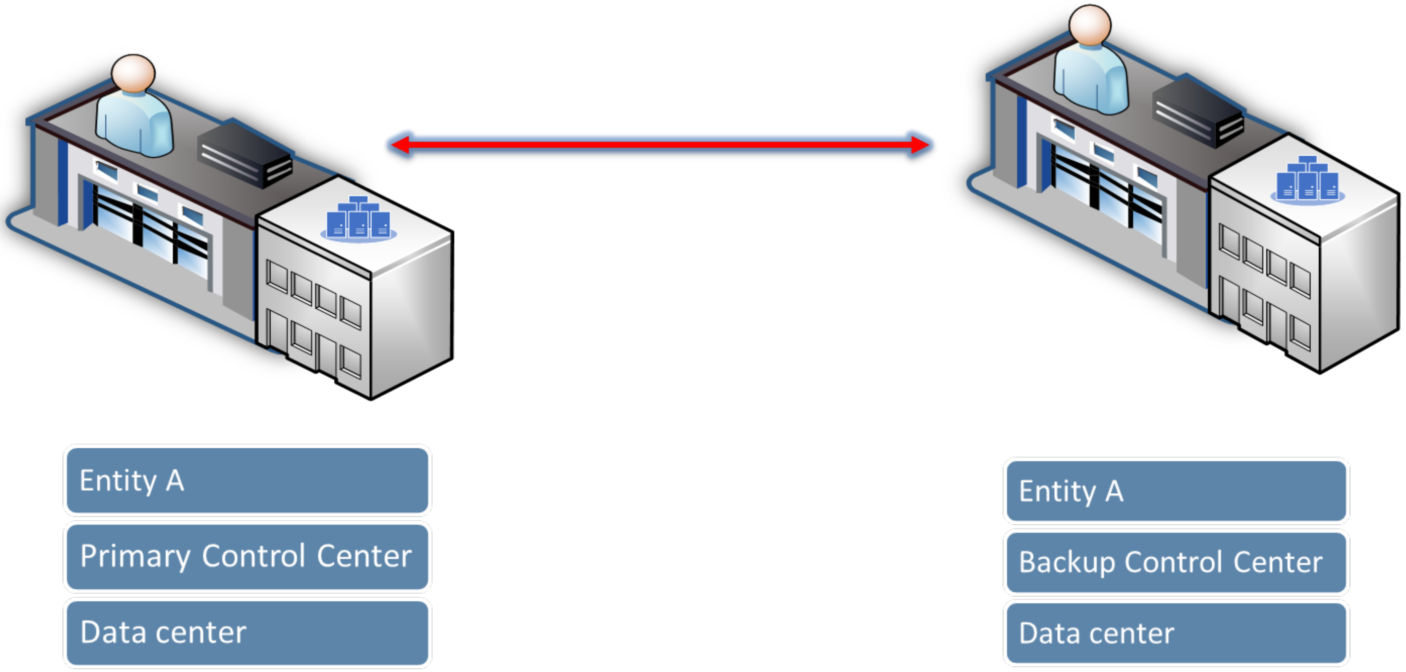
Communication between Control Centers	• Communication paths and all way points or hops and skips
Facility to Facility Communication	• Logical, physical, and other protections
RTA/RTM	• IRO-010-3 |TOP-003-4 |NPCC Whitepaper on NERC Reliability Standard CIP-012, Page 9

Control Centers Definition Visualization



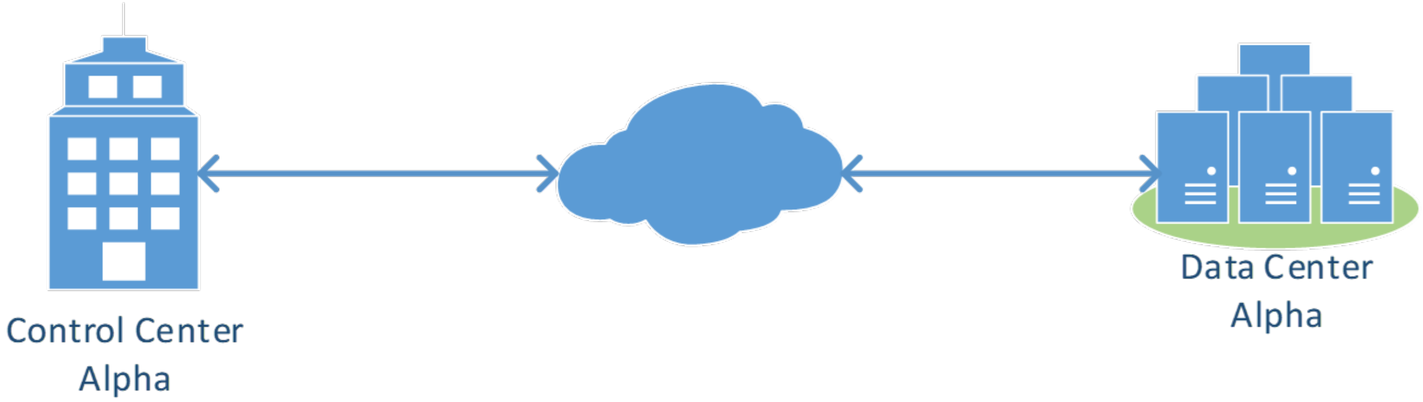
Traditional Entity Layout

- Entity has a PCC and ACC
- Internal to the entity communication paths.



Control Center Communicating with an Associated Data Center

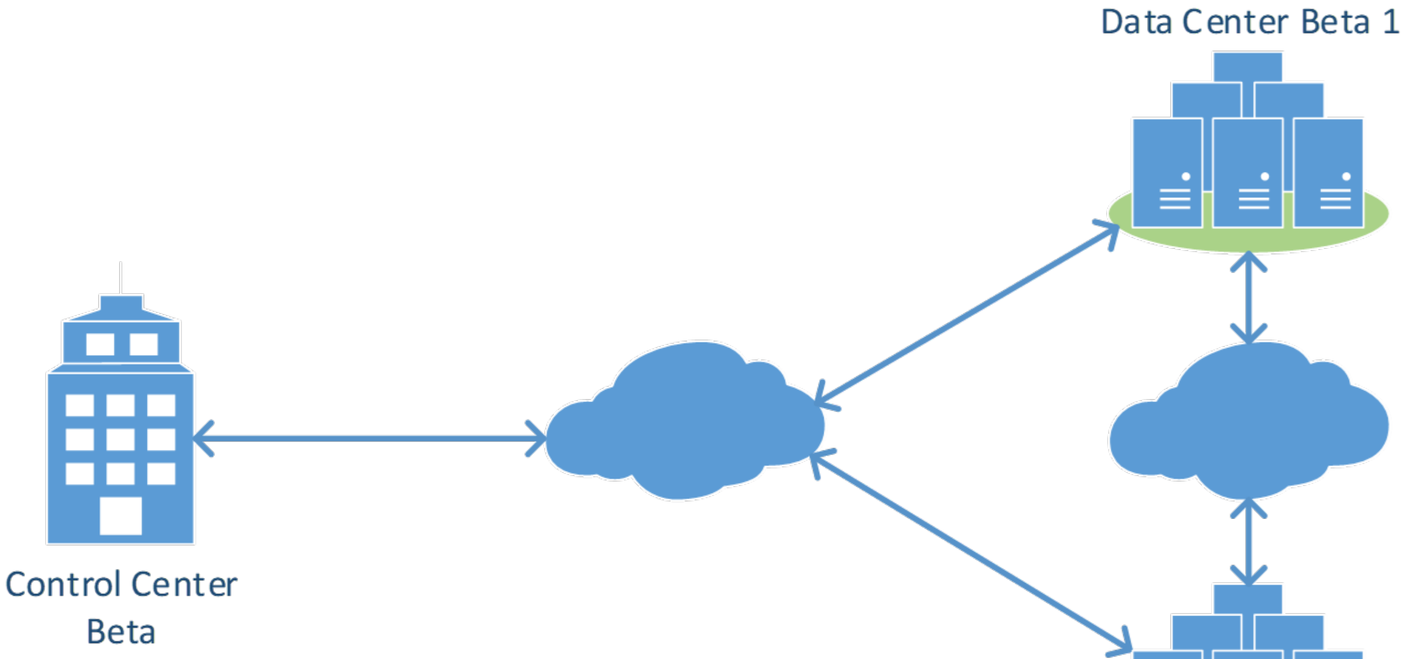
- Path between Locations need to be protected.
- Any Communication Transfer or waypoints need to be defined in the CIP-012 Plan.



Control Center with an Associated, Geographically Separate Data Center

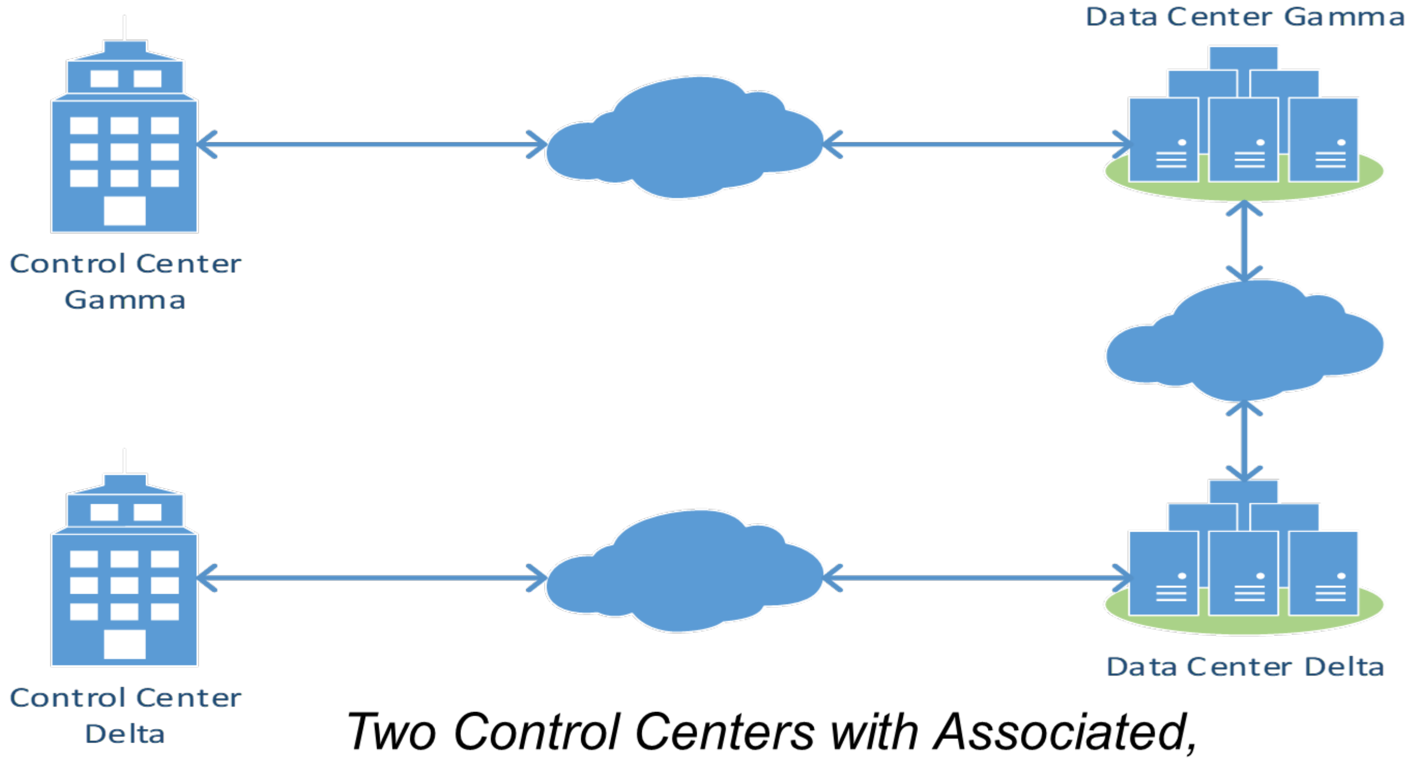
Control Center with Multiple Data Centers

- RTA/RTM Communication from Control center to Data centers
- RTA/RTM Communication between Data centers need to be protected.
- Hops and Skips in the communication path need to be accounted for.



Control Center with two Associated, Geographically Separate Data Centers

RTA/RTM Data being Exchanged by Data Centers



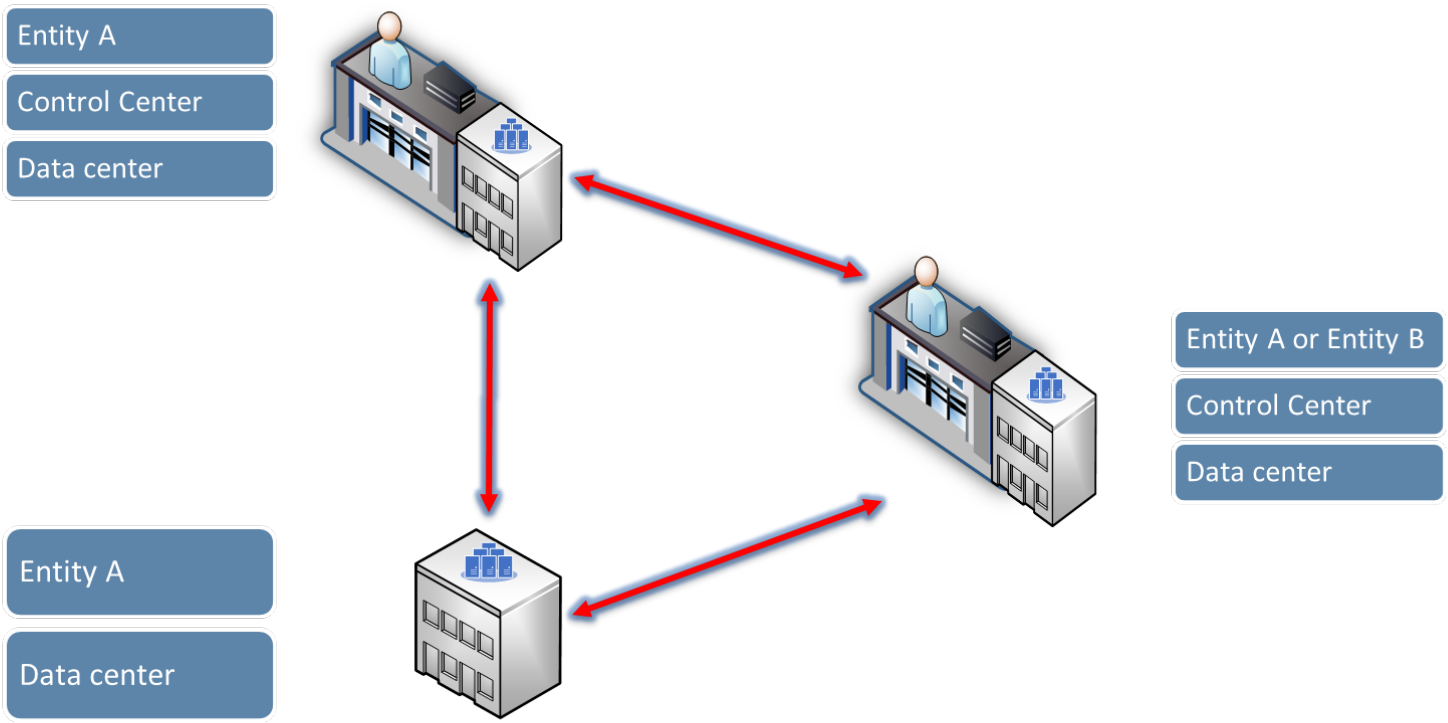
Two Control Centers with Associated, Geographically Separate Data Centers

Entity RTA\RTM Communication Scenario

- Internal Entity communication

  or

- Entity to Entity communication



RTM Data SGAS CIP-012 FAQ

Covers CIP-12 Questions about:

- Scope
- Agreements
- Audit Approach
- CIP Exceptional Circumstances (CEC)
- Control Center
- Controls
- EIDSN
- Enforcement
- Evidence
- Hops and Skips
- Implementation
- Plan
- Risk

Protections

- Identification of security protection used to mitigate the risks posed by unauthorized disclosure and unauthorized modification of Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers;

Protect | Monitor | Detect | Alert | Respond

- **Encryption**
  - Vendor Encryption: EIDSN
  - Entity Applied Encryption
- **Physical Protections**
  - Walls, Conduit, Alarming, Monitoring, Physical Structures
- **Internal Controls**
  - Network Monitoring

CIP-012-1 RSAW

- NEC Published by NERC on May 3, 2022

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standard Audit Worksheet[1]

CIP-012-1 – Cyber Security – Communications between Control Centers

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Name of Registered Entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1	X		X	X		X			X	X		

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

Compliance Approach

- Verify the entity has applicable controls centers.
- Verify RTA/RTM Data being exchanged between control Centers.
- Documented Plans to Mitigate unauthorized disclosure and modification .
- Identification of Security Protections.
- Where the entity has applied security protections.
- Verify security protections are applied to control center communications between different entities.
- Implementation of CIP-012 security plan.
- Verify that the entity CIP-012 plan achieves the objective of mitigation unauthorized disclosure and unauthorized modification.
- Verify any CEC that are declared by CIP-012 Adhere to Entity Cyber Security Policy.

Compliance Evidence

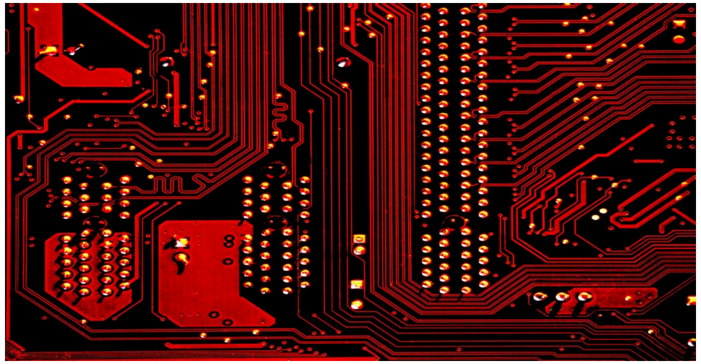
What do you consider RTA/RTM? (R1.1)		Identification of Security protections used in the communication Route? (R1.2)		Are you a Control Center and whom are you communication with? (R1.3)		
List of communication Data you protect	Justification for Inclusion or Exclusion	Logical, Physical, Monitoring, Other Controls and protections	Procedures, Diagrams with Security Demarcations	Entity Assessment	Identification of connected control centers and Communication Paths	Agreement/ MOU with between entities

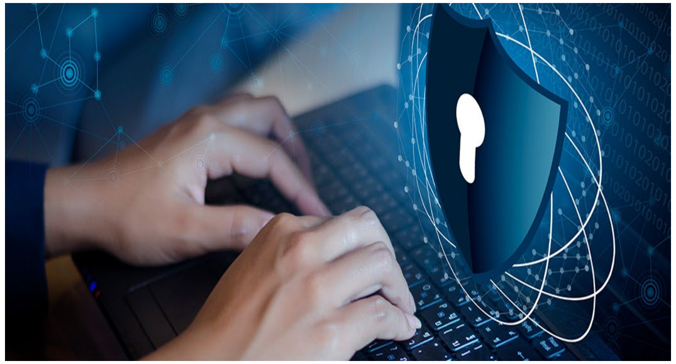
Controls

- Set review of connected Control centers
- Set review what is RTA/RTM
- Set Review time frame of Encryption or Security protocols.
- Encryption Key Management
- List of Security controls: Network monitoring, Network Configurations, Network diagrams, physical protections, Physical Perimeter diagrams, Change of Security Controls Demarcation.

Controls Continued

- Auditing or reassessment of Third-Parties
- Is unauthorized disclosure and unauthorized modification in your Incident Response Plan?





Break

Compliance Monitoring Program Updates

Jacqueline Jimenez
Director, Compliance

Emily Stuetzle
Senior CIP Analyst

NPCC, Inc.

Agenda

Standards Update

CIP ERT v6 Update

NP Verify

Internal Controls RFI Update

Hybrid On-site Audits

Standards Update

July 1, 2022

- **New Standard**: CIP-012-1 – Cyber Security – Communications between Control Centers
- PRC-002-2 — Disturbance Monitoring and Reporting Requirements
  - 100% compliance for Requirements R2 – R4, R6 – R11

Standards Update

CIP-005-6

- Current version
- Effective October 1, 2020

CIP-005-7

- New version
- Effective **October 1, 2022**

Standards Update

CIP-005-7 Changes

Added R3 which is applicable to:	EACMS and PACS associated with High Impact BES Cyber Systems EACMS and PACS associated with Medium Impact BES Cyber Systems with External Routable Connectivity
New Requirement R3 Part 3.1	**Requirement:** Have one or more method(s) to determine authenticated vendor-initiated remote connections.
New Requirement R3 Part 3.2	**Requirement:** Have one or more method(s) to terminate authenticated vendor-initiated remote connections and control the ability to reconnect.

Standards Update

CIP-010-3

- Current version
- Effective October 1, 2020

CIP-010-4

- New version
- Effective **October 1, 2022**

Standards Update

CIP-010-4 Changes

Added to the *Applicable Systems* for R1.6:

High Impact BES Cyber Systems and their associated:	**1. EACMS; and** **2. PACS**
Medium Impact BES Cyber Systems and their associated:	**1. EACMS; and** **2. PACS**

Note: Implementation does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders). Additionally, the following issues are beyond the scope of Part 1.6: (1) the actual terms and conditions of a procurement contract; and (2) vendor performance and adherence to a contract.

No change to the requirement language itself

Standards Update

CIP-013-1

- Current version
- Effective October 1, 2020

CIP-013-2

- New version
- Effective **October 1, 2022**

Standards Update

CIP-013-2 Changes

Added EACMS and PACS to Requirement R1 Header:	Each Responsible Entity shall develop one or more documented supply chain cyber security risk management plan(s) for high and medium impact BES Cyber Systems **and their associated EACMS and PACS**. The plan(s) shall include:
Requirement R1 Part 1.1	One or more process(es) used in planning for the procurement of BES Cyber Systems **and their associated EACMS and PACS** to identify and assess cyber security risk(s) to the Bulk Electric System from vendor products or services resulting from: (i) procuring and installing vendor equipment and software; and (ii) transitions from one vendor(s) to another vendor(s).
Requirement R1 Part 1.2	One or more process(es) used in procuring BES Cyber Systems**, and their associated EACMS and PACS**, that address the following, as applicable:
Requirement R1 Part 1.2.5	Verification of software integrity and authenticity of all software and patches provided by the vendor for use in the BES Cyber System **and their associated EACMS and PACS**; and
Requirement R1 Part 1.2.6	Coordination of controls for ~~(i)~~ vendor-initiated ~~**Interactive**~~ **remote access.** ~~**and (ii) system-to-system remote access with a vendor(s).**~~

Standards Update

PRC-024-2

- Current version
- Effective July 1, 2016

PRC-024-3

- New version
- Effective **October 1, 2022**

Standards Update

PRC-024-3 Changes

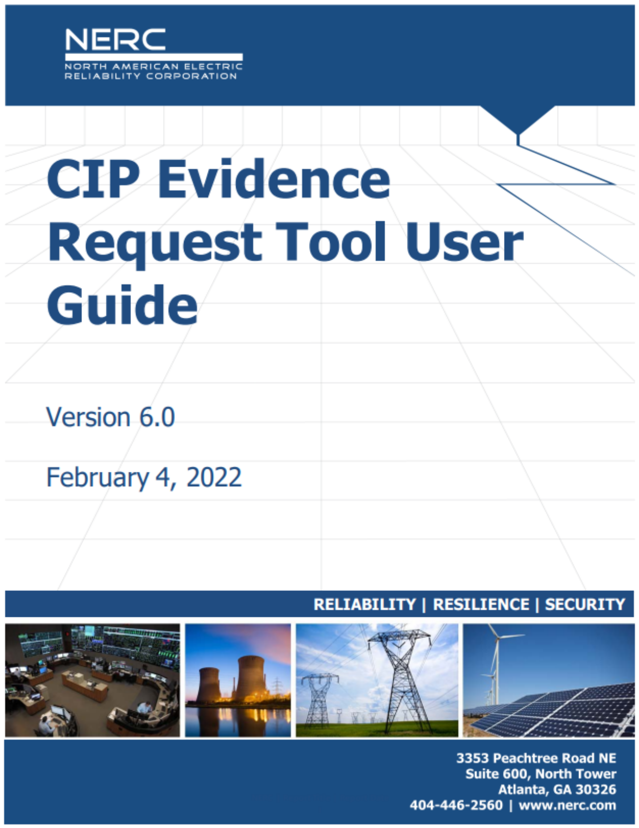
Expanded the Applicability Section: Facilities Section added that explicitly lists protective functions for specific equipment	Plant Auxiliary Equipment is not included as an applicable facility Specifies that voltage and frequency protection should be applied to both generator step-up (GSU) and collector transformers
Includes TOs and PCs as Functional Entities	Quebec Interconnection only

- Requirements R1 and R2 modified to specify that a generating resource may neither trip NOR enter momentary cessation inside the No Trip Zone
- Diagrams in the Attachments updated to clarify the area outside the "No Trip Zone" is not a "Must Trip Zone."
- Removed the term "point of interconnection" and replaced with "at the high side of the GSU or collector transformer."

Standards Update

January 1, 2023	• TPL-007-4 R3, R4, R8 • Phased-in Implementation Plan
April 1, 2023	• EOP-011-2 Emergency Preparedness and Operations • IRO-010-4 Reliability Coordinator Data Specification and Collection • TOP-003-5 — Operational Reliability Data
July 1, 2023	• TPL-001-5.1 — Transmission System Planning Performance Requirements

CIP ERT v6 Update



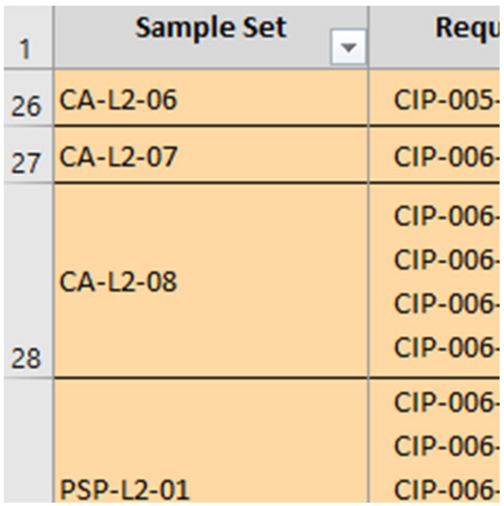
Sent with audit notification package

Available on NERC website

[CIP ERT Version 6.0 User Guide]

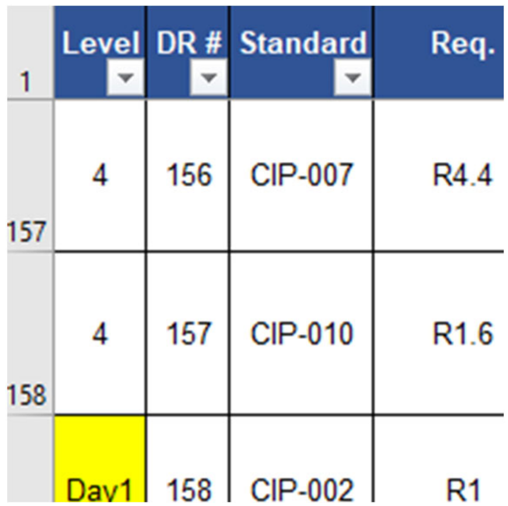
[v5 to v6.0 Change List]

CIP ERT v6 Update



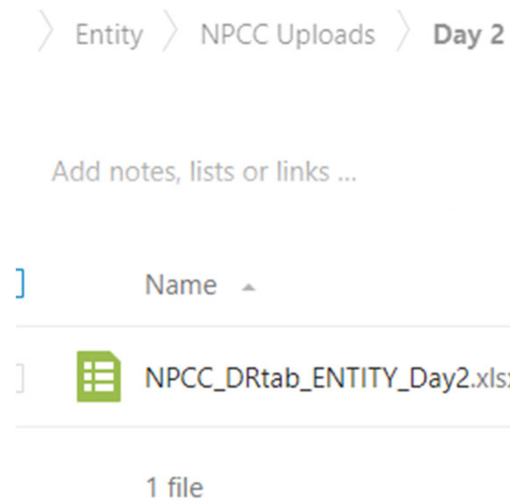
	Sample Set	Requ
26	CA-L2-06	CIP-005-
27	CA-L2-07	CIP-006-
28	CA-L2-08	CIP-006- CIP-006- CIP-006- CIP-006-
	PSP-L2-01	CIP-006- CIP-006- CIP-006-

Updated Sample Set naming convention



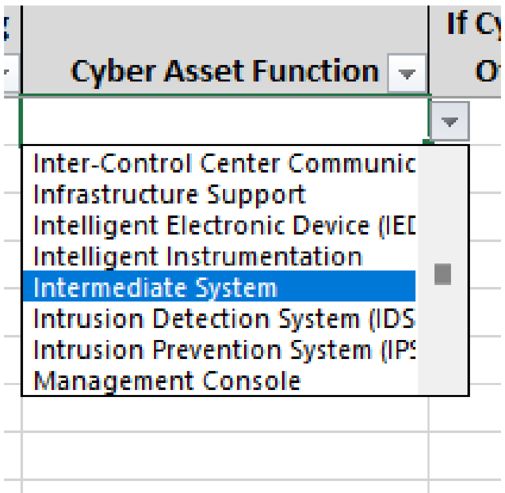
	Level	DR #	Standard	Req.
157	4	156	CIP-007	R4.4
158	4	157	CIP-010	R1.6
	Day1	158	CIP-002	R1

Added "Level" Column in NPCC tab

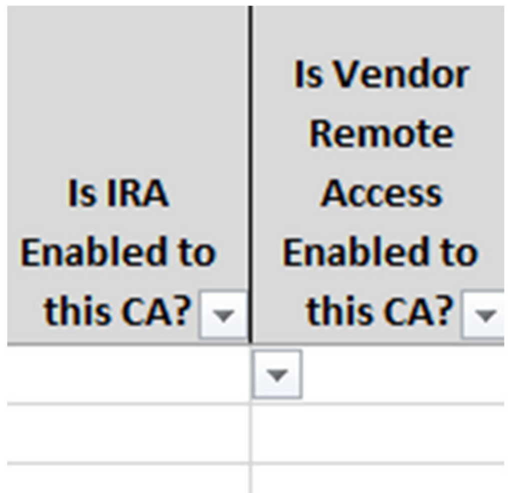


Separated NPCC tab from ERT after L2

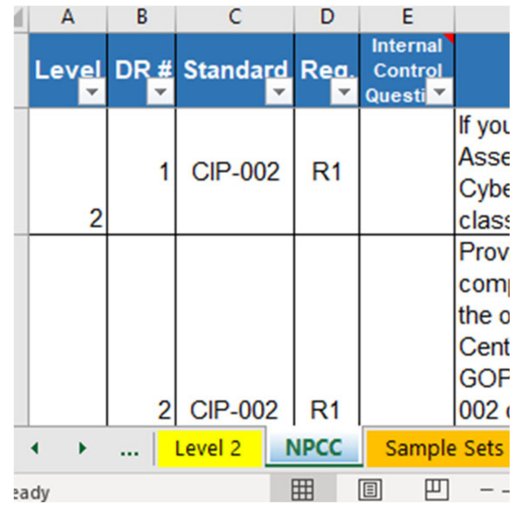
ERT Common Errors



Cyber Asset Function – Intermediate System

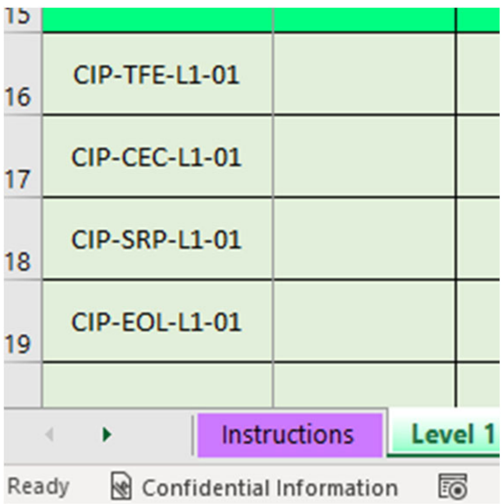


Is IRA Enabled to this CA?

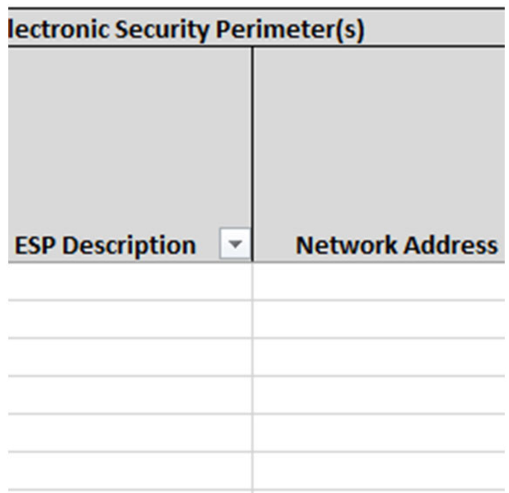


NPCC tab Level 2 requests

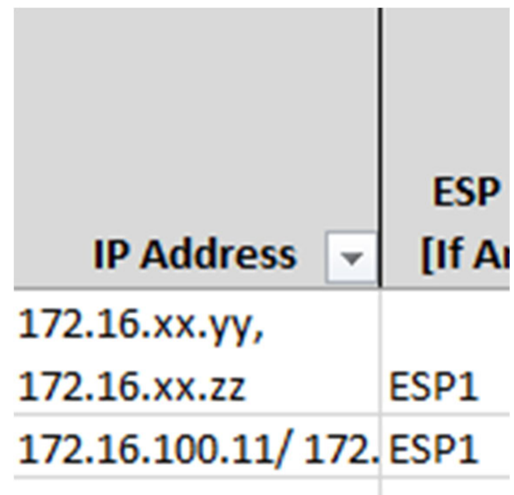
ERT Common Errors



Missing the four general Level 1 requests

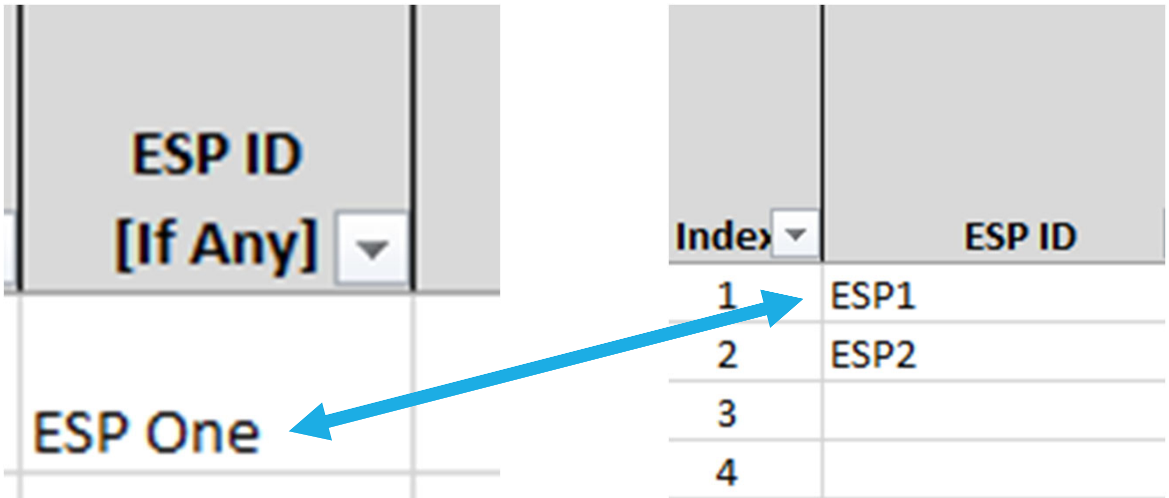


Missing ESP address spaces

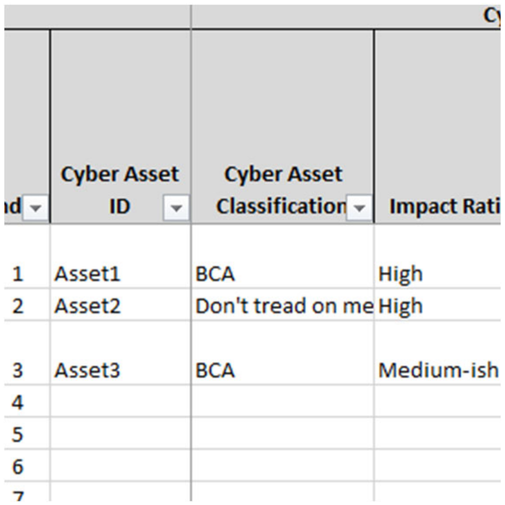


Multi-line entries

ERT Common Errors



CA tab ESP ID not matching
an entry on the ESP tab



Altering the ERT

NP Verify

App to verify that network configs will properly import into NP-View

Network-Perception support will be limited with the ERO SEL

https://network-perception.com

https://network-perception.com/kb/firewalls-routers-switches

Internal Controls RFI Update

NPCC assess internal controls as part of monitoring engagements.

- Pre-audit RFI
- RFIs during evidence review

New - NPCC may have additional high level internal controls questions following the pre-audit RFI submittal.

- The additional internal controls RFI will be sent approximately 2 weeks after receipt of the pre-audit RFI submittal, which will be due with the RSAW and evidence submittal.

NPCC will continue to ask internal controls RFIs during the review of RSAWs and evidence, as needed.

NORTHEAST POWER COORDINATING COUNCIL, INC.

Hybrid On-site Audits

On-site activity to resume

Expected to resume in Q3 2022

Hybrid audit approach

- Virtual interviews
- On-site inspections
  - Control Center tours
  - FAC-008
  - Cyber
  - Small sub-set of audit team

Determine entity COVID-19 protocols

COVID-19 Protocol Survey

Questions

Jacqueline Jimenez
jjimenez@npcc.org

Emily Stuetzle
estuetzle@npcc.org

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

FERC/ERO Protection System Commissioning Program Review Project

Rich Bauer
Associate Principal Engineer – Event Analysis

NPCC Compliance/Reliability Webinar
May 17, 2022

RELIABILITY | ACCOUNTABILITY




Background

- Efforts to reduce Misoperations resulting from less than adequate Protection System Commissioning
  - 2015-2021 NERC SPCWG Issued Lessons Learned – Verification of AC Quantities
  - 2017 IEEE WG I-25 guide Commissioning Testing of Protection Systems
  - 2019 Analysis of Protection System Misops

FERC staff review of MIDAS data

- Process: Sample 'Event Description' and 'Corrective Action' MIDAS fields to determine PSC impact on Misops.
- Finding: 18 – 36% of Misops could be attributed to issues that PSC should have detected.

Commission Testing Review

Joint Review of Protection System Commissioning Programs

2021 FERC, NERC and REs Report

November 2, 2021

FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation and its Regional Entities

The matters presented in this staff report do not necessarily represent the views of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.

Review Process

- Eight registered entities and one PSC contractor.
- Selected based on geographical locations and performance data such as events and Misop rates.
- Surveys and Interviews on participants’ PSC programs and Procedures.
- Used the IEEE PSRC WG I-25 guide as a benchmark.
- Team discussed and agreed upon the best practices, opportunities for improvement, and related recommendations.

WG I-25

- **NERC request to IEEE PSRC**
- **IEEE PSRC I-25 Working Group**
- **Report on Commission Testing Practices**
- **Report to serve as Industry Reference**

IEEE PSRC, WG I-25 May 10, 2017

Commissioning Testing of Protection Systems

Assignment:

To create a report, at the request of the North American Electric Reliability Corporation (NERC) System Protection and Control Subcommittee (SPCS), to serve as an industry reference document on protection system testing practices. The SPCS believes that it would be beneficial for IEEE to produce a document on commissioning testing in an effort to help reduce the number of misoperations resulting from improper commissioning.

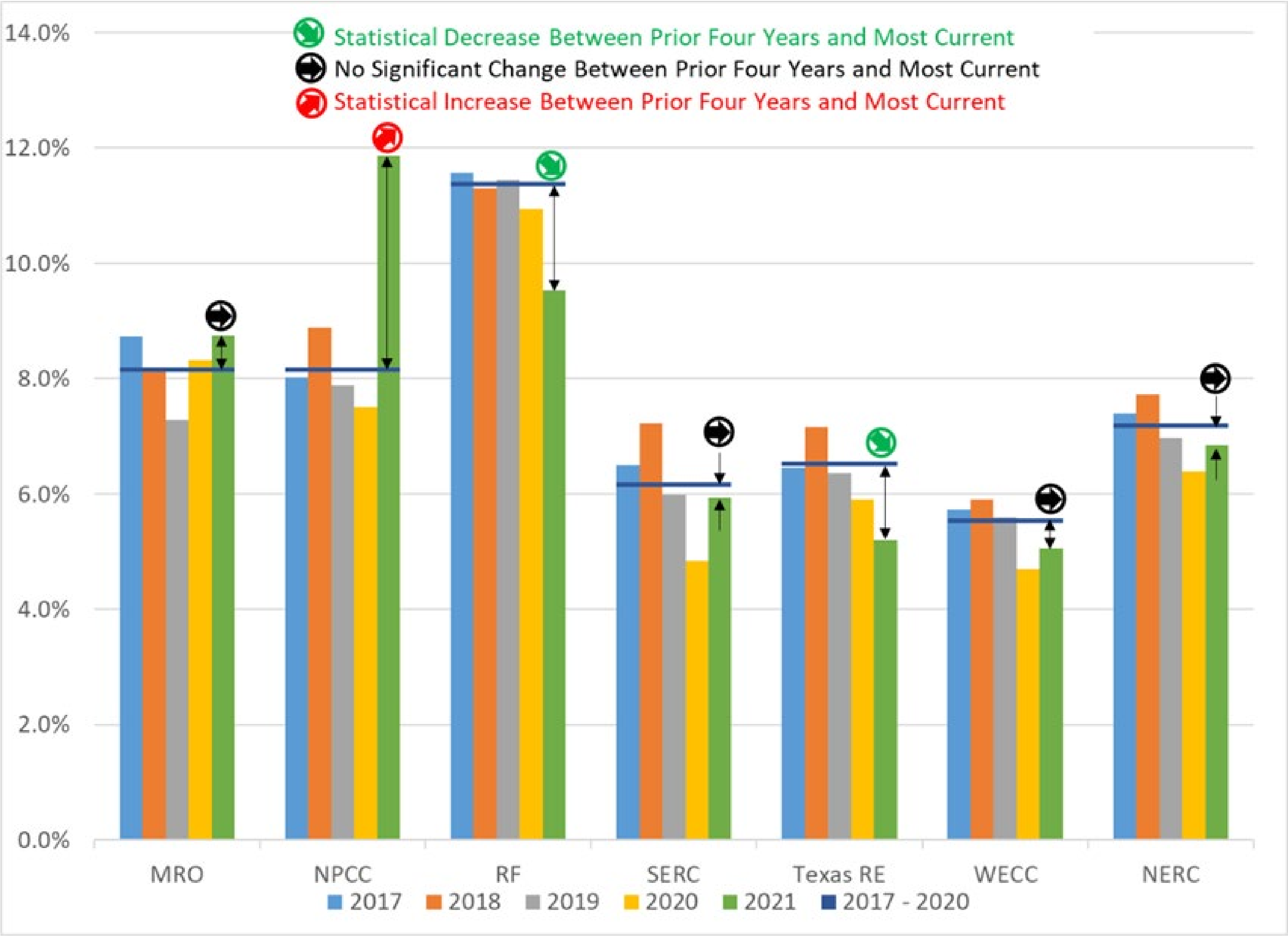
Working Group Members:

R. Garcia (Chair); K. Donahoe (Vice-Chair); R. Aguilar; A. Apostolov; H. Ashrafi; J. Barsch; N. Bilimoria; J. Brown; C. Bryant; D. Buchanan; E. Carvalheira; N. Casilla; G. Halt; W. Knapek; A. Lee; B. Mackie; H. Malson; B. Moores; G. Moskos; A. Newman; L. Polanco; S. Saminfni; E. Schock; T. Seegers; M. Siira; M. Stojak; A. Uribe; J. Verzose; D. Ware; M. Wright; V. Yedidi

PSC Programs

- All participants but one had a formal commissioning program; however, none of the participants' programs were as comprehensive as the IEEE WG I-25 guide recommends.
- No participant maintained a centralized document that contained all five key elements of an effective PSC program.
- Recommendation
  - All entities should document a formal PSC program. Having a formal, documented program in a central location (e.g., a single document) allows easy reference to all the elements of the program.

2022 SOR Misoperations



Questions

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Cell (404) 357-9843
rich.bauer@nerc.net

Aspects of Grid Transformation

Ensuring Reliability of the Electricity Ecosystem

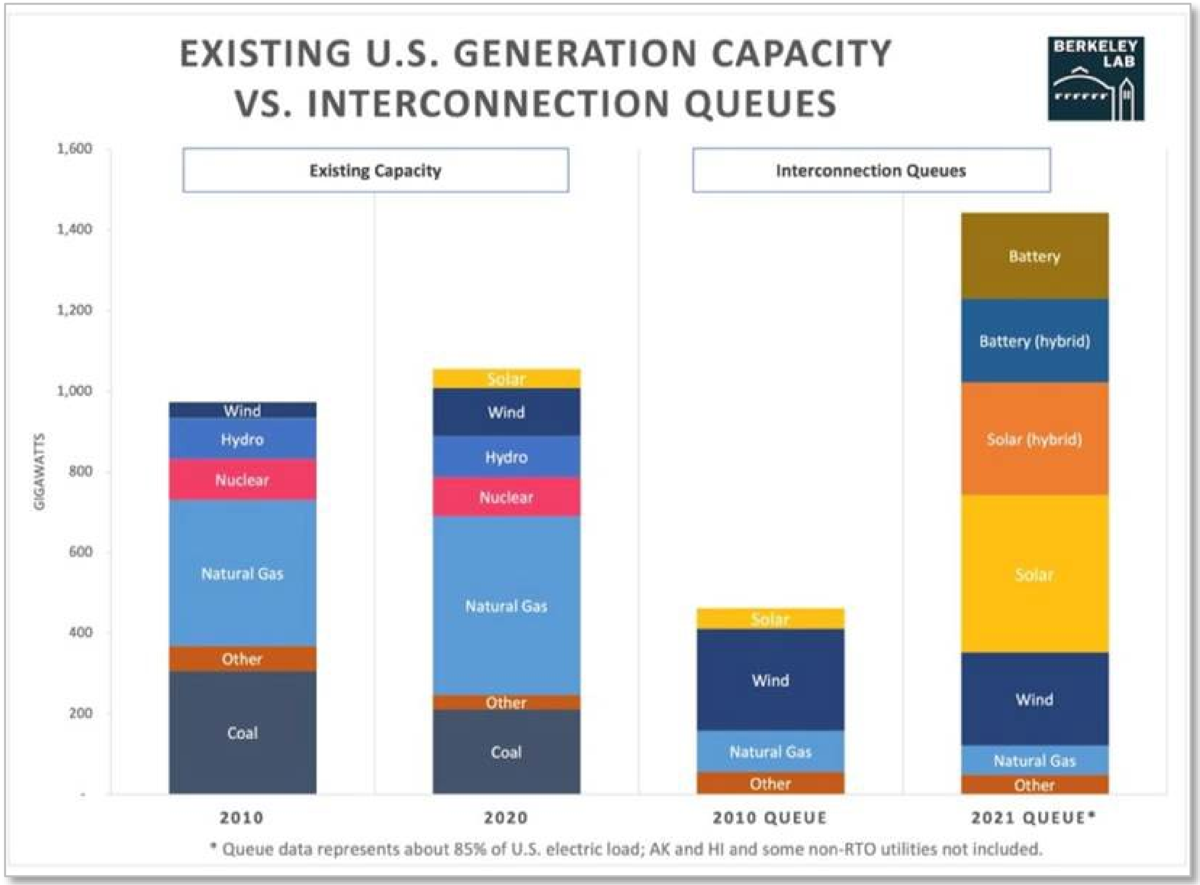
Ryan D. Quint, PhD, PE
Senior Manager, BPS Security and Grid Transformation
North American Electric Reliability Corporation

May 2022

RELIABILITY | RESILIENCE | SECURITY




Decarbonization

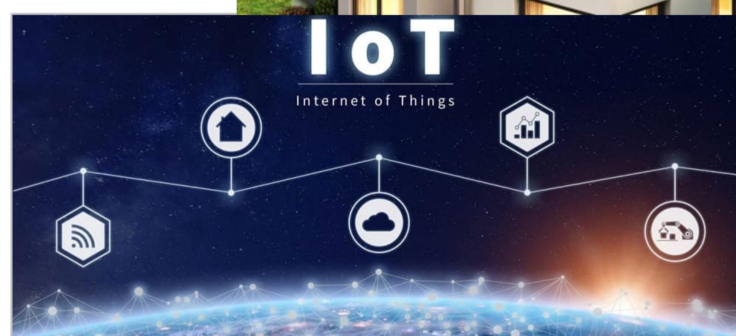


Source: LBNL

- Synchronous generation retirement
- Inverter-based resource boom
  - Variability and uncertainty
- Need for flexibility
  - Battery energy storage systems
  - Hybrid plants
- BPS reliability impacts
  - Energy and resource adequacy
  - Essential reliability services
  - Reframing reliability considerations
  - Modeling and studies

Distributed Control

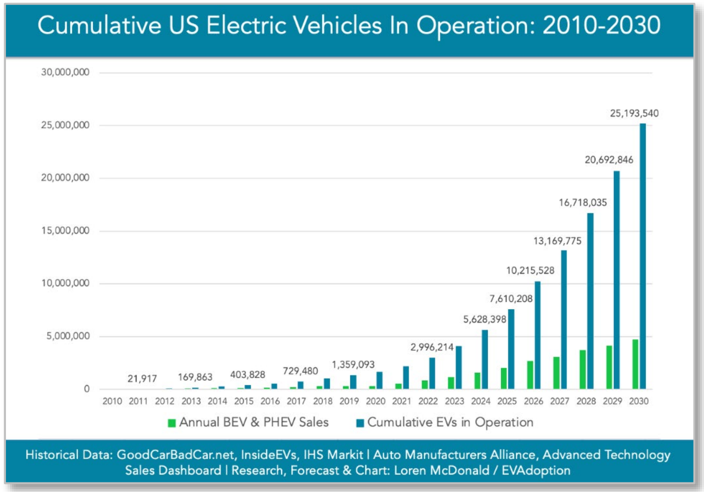
- Distributed Control
  - Prosumers
  - Smart meters
  - Demand-side management
  - Distributed energy resources
  - DER Aggregators
  - Microgrids
  - V2G and V2X
  - Grid edge analytics
  - Internet of Things
  - Industrial Internet of Things



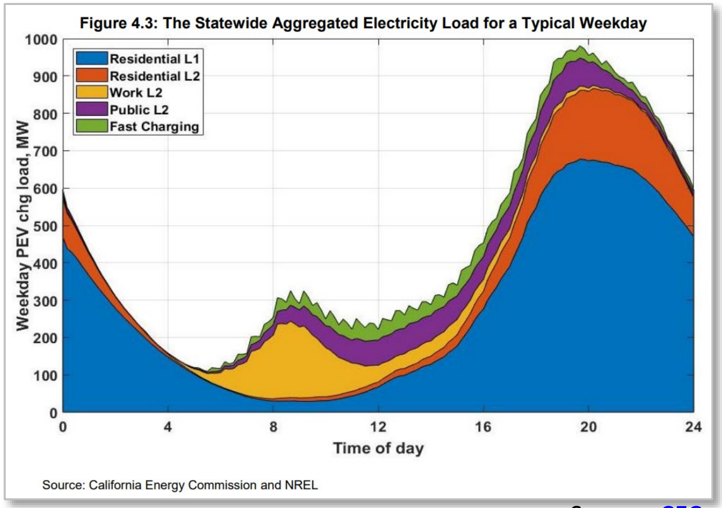
Source: HP

Transportation Electrification

- Managed versus unmanaged charging
- Rapid or unexpected changes in demand
- Ramping implications
- Correlation with solar PV output
- Need for grid-friendly charging
- System implications and oscillations
- Fault ride-through performance
- System restoration and blackstart plans
- Power quality – harmonics and flicker
- V2G and V2X
- Participation in DER Aggregation



Source: EV Adoption



Source: CEC

Critical Infrastructure Interdependence

- Natural gas supply
  - Possible winter reliability risks with disruption of supply in New England, California, and U.S. Southwest
  - "Just-in-time" fuel source
  - Lack of firm natural gas delivery to generators during peaks
  - Limited natural gas pipeline capacity and lack of redundancy

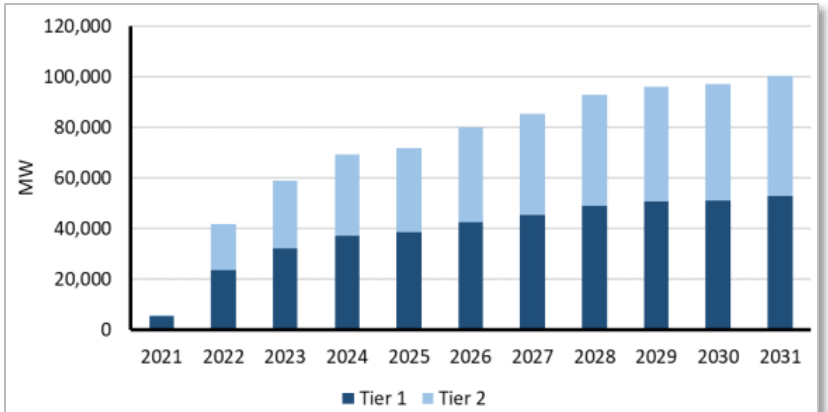
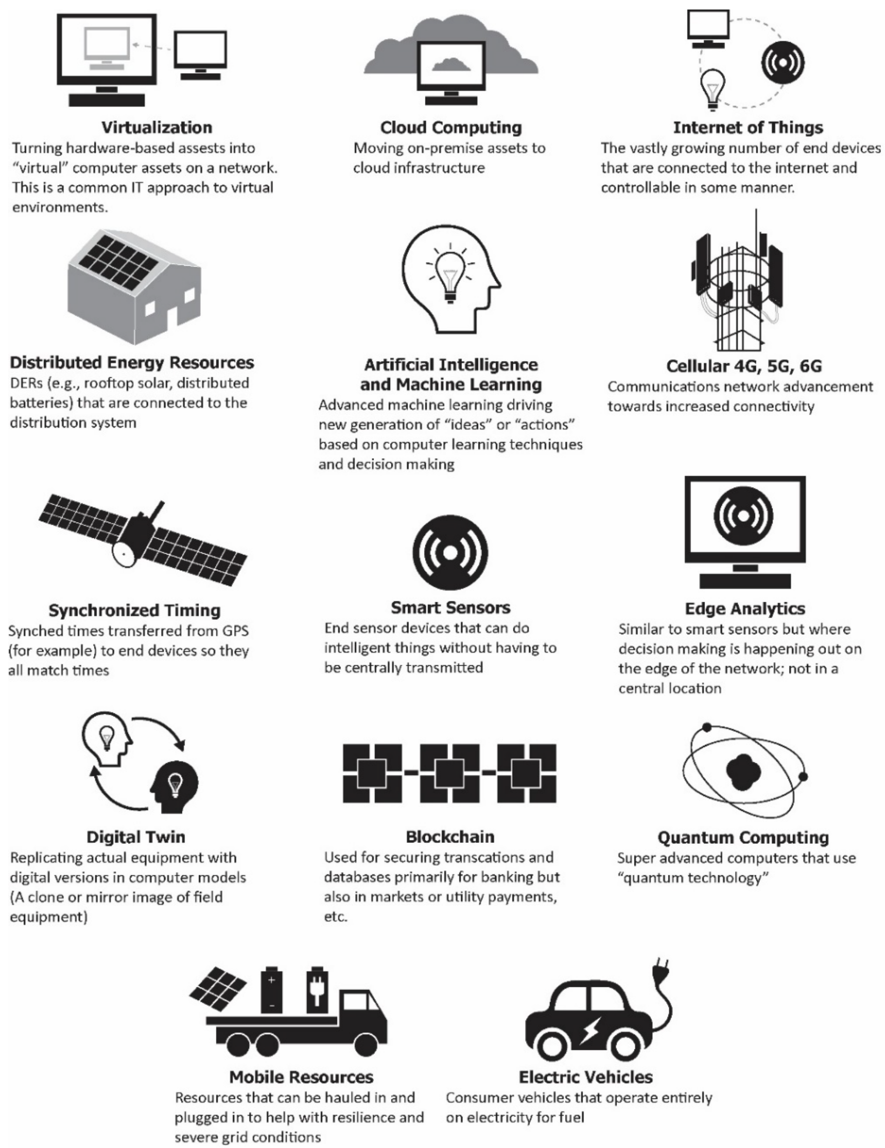


Figure 20: Natural Gas Capacity Planned Additions through 2031, Tier 1 and 2

- Telecommunications
  - IT and operational technology (OT) uses
  - Linked to critical safety, reliability, and security functions

Digitalization and Emerging Technologies



Emerging technology:

A combination of techniques, skills, methods, or processes whose use, development, or practical application are largely unrealized, not widely adopted, in development, or otherwise still early in their demonstration and maturation.

Critical Thinking Needed

- Are current planning, design, and operations practices sufficient with a future dominated by inverter-based resources, distributed energy resources, and grid-edge technologies?
- Are grid planners and operators preparing for multi-sector electrification and reliance on other critical infrastructures?
- Are we prepared for a rapidly evolving attack surface and to securely integrate emerging technologies?
- Can we more deeply integrate cyber and physical security aspects into engineering/business activities?
- How can we *proactively* prepare for the changing landscape in an agile, effective, and efficient manner to ensure reliable operation of the BPS?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Questions and Answers

Ryan Quint, PhD, PE
Senior Manager
BPS Security and Grid Transformation
North American Electric Reliability Corporation
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Cell (202) 809-3079
ryan.quint@nerc.net

NPCC 2022 Outreach Activity

Gerry Dunbar

Director Reliability Standards and Criteria

May 17, 2022

NPCC, Inc.

NPCC 2022 – 2025 Strategic Plan

Strategic Focus Area

Reliably Integrate Resources Brought Forward by Decarbonization Objectives

- NPCC DER/VER Forums
  - Sponsored by the Regional Standards Committee
  - Focused on Specific Decarbonization Topics
- DER/VER Forums --- 2022 Activity
  - May 2022 Impact of EV Charging on the BPS
  - Additional Forums --- August and October
  - Building Electrification

NPCC 2022 – 2025 Strategic Plan

Strategic Focus Area

Reliably Integrate Resources Brought Forward by Decarbonization Objectives

- NPCC DER/VER Guidance Document
  - Stakeholder Reporting Form
- Proliferation of DER on UFLS Distribution Feeders
- NPCC 2023 Regional UFLS Assessment

NPCC 2022 Planned Outreach Activity

Comments /Suggestions:

Gerry Dunbar
NPCC Director Standards and Criteria
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Ruida Shu
NPCC Manager Reliability Standards
RShu@NPCC.org

NPCC 2022 Corporate Goals

DER Guidance Document

Who's Who of NPCC CMEP Staff

Michael Bilheimer
Senior CIP Analyst

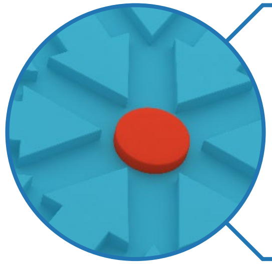
NPCC 2022 Spring Compliance and Reliability Webinar

NPCC, Inc.

Presentation Goals

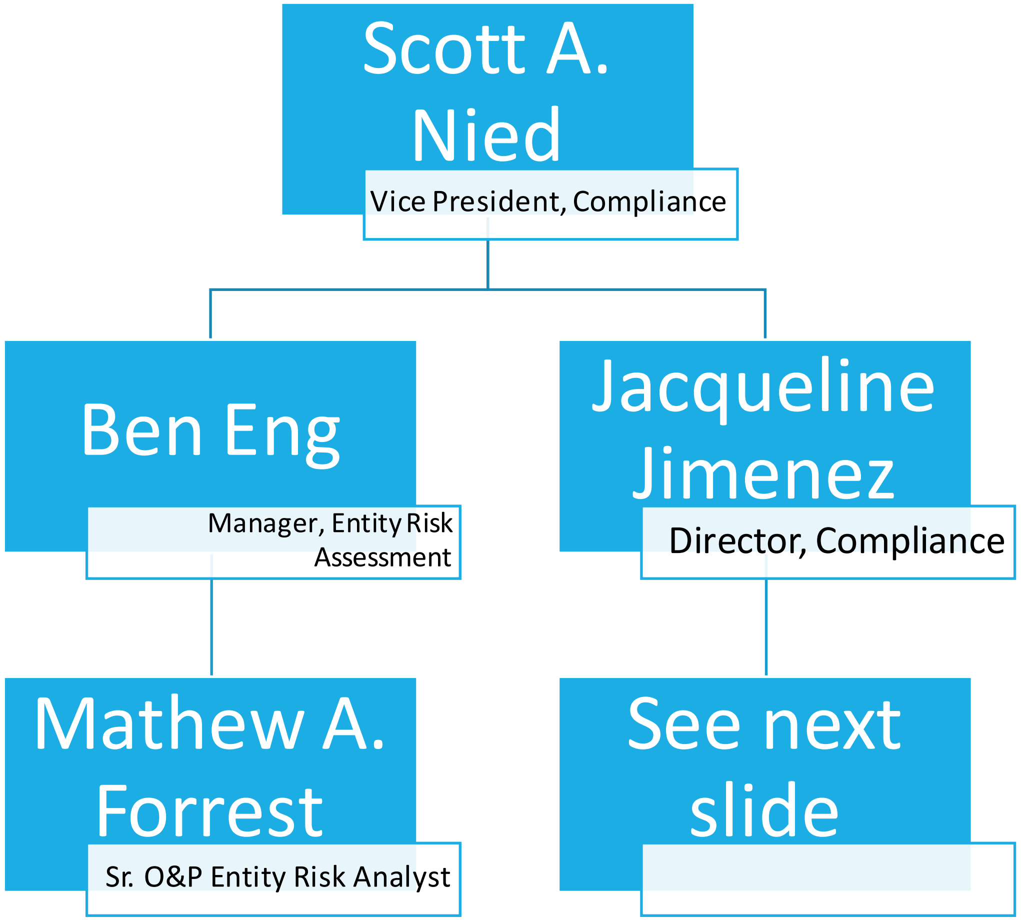
Go over staff updates.

Inform Entities of who they can contact and talk to.



Focused on Compliance Monitoring and Enforcement Program (CMEP) Departments

Compliance Monitoring



Compliance Monitoring

Jacqueline Jimenez – *Director, Compliance*

O&P Auditors

- Daniel Kidney – *Senior Compliance Engineer*
- Duong Le – *Senior Compliance Engineer*
- George Dong – *Senior Compliance Engineer*
- Kimberly Griffith – *Senior Compliance Engineer*
- Mujahid Mian – *Senior Compliance Engineer*

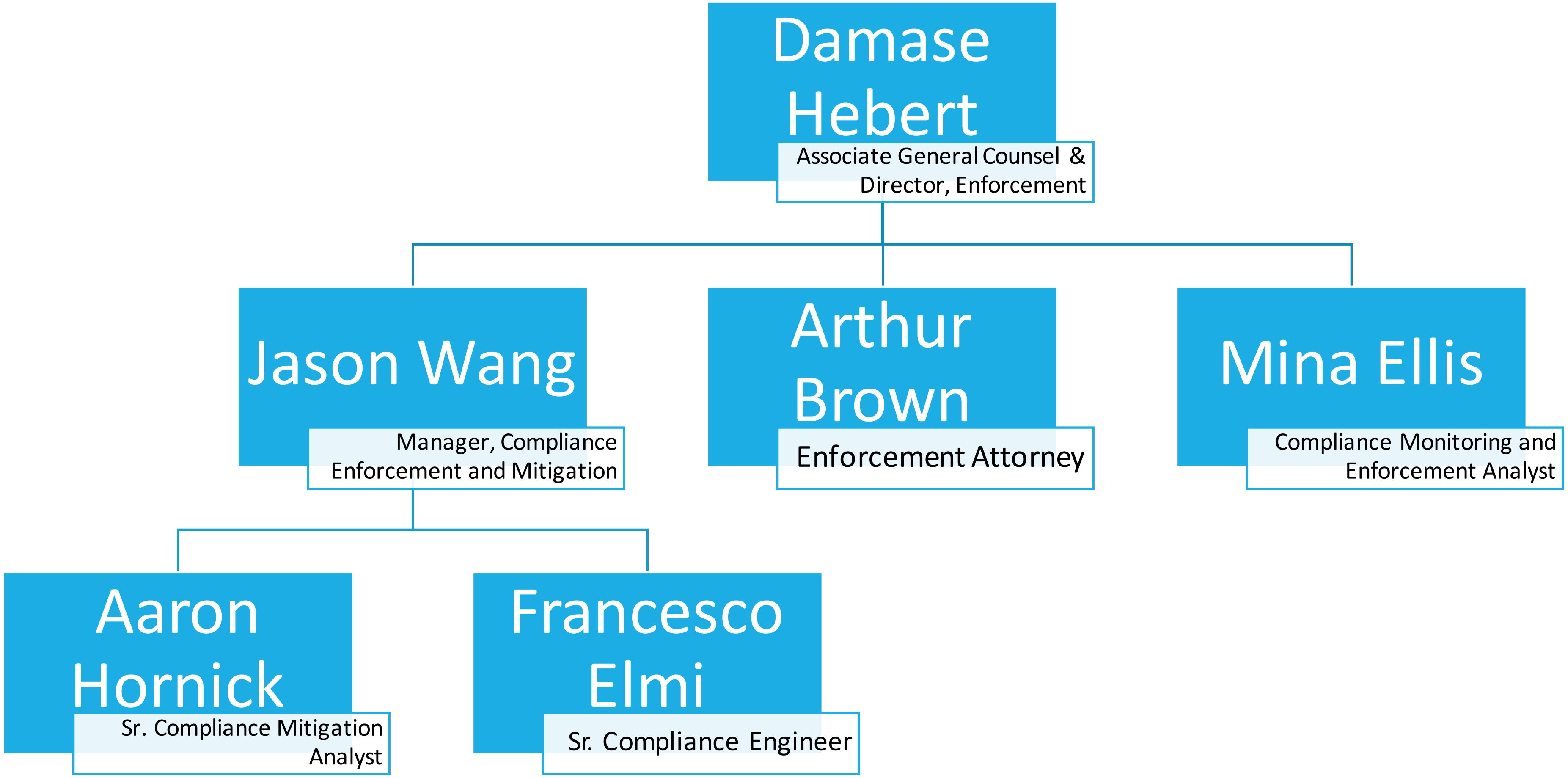
CIP Auditors

- Catherine Nakor-Tetteh – *Compliance Auditor*
- Cecil Elie – *Senior CIP Analyst*
- Emily Stuetzle – *Senior CIP Analyst*
- Michael Bilheimer – *Senior CIP Analyst*

CIP and O&P Auditors

- Patrick Palompo – *Senior Compliance Engineer*
- Travis Tate – *Senior Compliance Engineer*

Enforcement



CMEP Management Contacts

Scott Nied *Vice President, Compliance*	• snied@npcc.org
Damase Hebert *Associate General Counsel & Director, Enforcement*	• dhebert@npcc.org
Jacqueline Jimenez *Director, Compliance*	• jjimenez@npcc.org
Ben Eng *Manager, Entity Risk Assessment*	• beng@npcc.org
Jason Wang *Manager, Compliance Enforcement and Mitigation*	• jwang@npcc.org

NPCC Contacts

General Email Contacts:

- **Compliance:** compliance-support@npcc.org
- **Bulk Electric System (BES):** registration@npcc.org

General Phone Numbers:

- 212-840-1070
- 212-921-1040

Website:

- NPCC Home Page
- https://www.npcc.org/about/contact-us