Agenda
NERC Quarterly Technical Session

February 14, 2024 | 12:30–3:00 p.m. Central
In-Person

The Houstonian Hotel Houston
111 North Post Oak Lane
Houston, TX 77024
Conference Room: Grand Ballroom (lower level)

Virtual Attendees
Webcast Link: Join Meeting

Introductions and Opening Remarks

NERC Antitrust Compliance Guidelines

Agenda Items

1. **Gas-Electric Coordination Panel* – Review**
2. **Cloud Technology Panel* – Review**
3. **Interregional Transfer Capability Study* – Update**
4. **Bulk Power System Awareness* – Update**
5. **Closing Remarks and Conclude Session**

*Background materials included.

Gas-Electric Coordination Panel

Action
Review

Panelists
- Todd Snitchler – President and CEO Electric Power Supply Association
- Amy Andryszak – President and CEO, Interstate National Gas Association of America
- Dena Wiggins – President and CEO, Natural Gas Supply Association
- Mark Lauby – Senior Vice President & Chief Engineer, NERC

Background
- Gas-Electric coordination (both commercial arrangements and operating coordination) has emerged as a key risk area during the energy transition as the role of natural gas fired generation has become increasing essential to provide the energy to meet load, grid essential reliability services, and the flexibility to integrate large amounts of variable energy resources such as wind and solar.
- The two subsectors are now more than interdependent, but interconnected with all the potential benefits, but potential risks that come from this interconnected energy system.
- The need for higher levels of coordination to address the interconnection risks between the two energy subsectors have been highlighted in multiple “cold weather event” investigations by NERC and FERC, notably 2021’s Winter Storm Uri and 2023’s Winter Storm Elliott reports.
- The North American Energy Standards Board (NAESB) launched at FERC and NERC’s request a forum on gas-electric harmonization that produced 20 recommendations, not all of which were embraced by the two sectors.
- The co-chairs of that Forum (Pat Wood, III, Sue Tierney, and Bob Gee) have proposed the formation of a Gas Reliability Organization, presumably formed along the lines of NERC, that would have regulatory authority to set and enforce Standards governing natural gas and coordinated at its interface with the electric system.
- Two of the Natural Gas Trade Associations (NGSA and INGAA) and the merchant generation Trade Association (EPSA) have proposed a number of steps / changes that may allow for better coordination between the two sectors (attached Whitepaper).

Panel Objectives and Discussion Topics
- This panel will explore the issue of gas-electric coordination and opportunities to improve from the perspective of the competitive energy providers as a complement to our own perspectives driven from our bulk power system reliability perch.
- The panel will explore four topics from the perspective of the panelists:
  - What are the issues we have seen during cold weather events that prompted the gas-electric harmonization forum to be formed in the first place?

- What are the risks and collaborative approaches needed to mitigate those risks from an interconnected energy (gas-electric) system perspective?
- How do the proposals put forth by the three trade organizations address those issues?
- What key issues remain if the proposals were adopted (e.g., operational performance beyond commercial coordination)? What alternatives exist to a GRO-type construct?

At the conclusion of the panel, NERC Leadership will lead a question and answer session.

Dena E. Wiggins
President and CEO, Natural Gas Supply Association

As NGSA's President and CEO, Dena Wiggins leads efforts to advance the natural gas industry's economic and environmental agenda with NGSA member companies, regulators, legislators and other key stakeholders. She manages daily operations of NGSA and is responsible for member relations, media engagement, advocacy and government affairs activities.

Dena has spent much of her professional career engaged in representing producer/marketers before the Federal Energy Regulatory Commission. She has testified before FERC on policy matters pending before the Commission and has been involved in every major natural gas rulemaking since Order No. 436. She frequently speaks with key Hill and White House staff, NARUC and other policymakers on the importance and benefits of natural gas use, supply and competitive markets. She has led hundreds of discussions on natural gas priority issues at conferences and is regularly quoted as an industry expert in the media, including *Reuters*, *S&P Global,* the *Houston Chronicle, Politico, Natural Gas Intelligence* and *RTO Insider*.

Dena is deeply involved in the National Association of Regulatory Utility Commissioners (NARUC), particularly the Committee on Gas, where she has advocated for the benefits of natural gas in a lower carbon energy future.

She represents NGSA at the Commodity Futures Trading Commission (CFTC) and chairs the CFTC's Energy and Environmental Matters Advisory Committee (EEMAC), which plans to explore the relationship between infrastructure constraints and natural gas markets.

Dena currently serves on the Board of the National Association of Manufacturer's Council of Manufacturing Associations and on the Board of the British-American Business Association. In addition, she serves on the Advisory Council of New Mexico State University's Center for Public Utilities and is a member of the Council Group of the American Bar Association's Infrastructure and Regulated Industries Section. She also serves on the Board of The Washington Ballet.

Previous to NGSA, she was a partner in the law firm of Ballard Spahr and served as General Counsel to the Process Gas Consumers Group. She holds a Bachelor of Arts degree from the University of Richmond and a Juris Doctor from Georgetown University Law Center.

TODD SNITCHLER

President and CEO, Electric Power Supply Association

Todd Snitchler is the president and CEO of the Electric Power Supply Association (EPSA). EPSA represents companies that own about 150,000 MW of capacity from competitive power generation assets throughout the U.S. and advocates for policies that focus on achieving and maintaining well-functioning and properly regulated competitive wholesale electricity markets.

Prior to joining EPSA, Todd served as the vice president of market development at the American Petroleum Institute where he worked with industry, government, and customer stakeholders to promote increased demand for and continued availability of our nation's abundant and clean natural gas resources.

Prior to that, Mr. Snitchler was a principal for Vorys Advisors, LLC in Ohio where he led government affairs efforts in the energy and utility space, representing competitive suppliers and independent power producers and developers. In that role, he established strong relationships in Ohio and nationally with policy makers and industry participants supportive of competitive markets.

Mr. Snitchler previously served as chairman of both the Public Utilities Commission of Ohio and the Ohio Power Siting Board. He was elected twice to represent the 50th House District in Stark County, Ohio.

Mr. Snitchler has published on numerous topics including the benefits of competitive energy markets; cyber security issues; electricity deregulation challenges; and the role of the federal Environmental Protection Agency. Mr. Snitchler received his J.D. from the University of Akron School of Law and his B.A. from Grove City College.

Amy Andryszak, President & CEO

Interstate Natural Gas Association of America and INGAA Foundation

Amy Andryszak was appointed President and Chief Executive Officer of the Interstate Natural Gas Association of America (INGAA) and the INGAA Foundation in 2020. INGAA represents natural gas transmission and storage companies who operate over 200,000 miles of pipeline and related infrastructure that safely transport natural gas from where it is produced to where it is consumed.

Since her appointment in 2020, Ms. Andryszak spearheaded the organization's 2021 Vision Forward, a comprehensive set of climate change commitments that focuses on modernizing our nation's interstate natural gas infrastructure with the goal of reducing emissions and minimizing climate impacts.

Prior to joining INGAA in 2020, Ms. Andryszak served as a Principal at a Washington, DC-based government relations firm where she managed a portfolio of clients across a range of policy areas, including energy and related infrastructure, telecommunications, travel and tourism, and financial services. With more than two decades of political and advocacy experience, Ms. Andryszak has held various leadership and executive positions in the U.S. House of Representatives and the private sector.

Ms. Andryszak received a bachelor's degree from The Pennsylvania State University. She volunteers as a reading mentor and board member of EverybodyWins! DC, a children's literacy non-profit dedicated to providing children the opportunity to share an enjoyable reading experience. Ms. Andryszak lives in Alexandria, VA with her husband and daughter.

Mark Lauby, Senior Vice President and Chief Engineer, NERC

Mark G. Lauby is senior vice president and chief engineer at NERC. Mr. Lauby joined NERC in January 2007 and has held a number of positions, including vice president and director of Standards and vice president and director of Reliability Assessments and Performance Analysis.

In 2012, Mr. Lauby was elected to the North American Energy Standards Board and was appointed to the Department of Energy's Electric Advisory Committee by the Secretary of Energy in 2014. Mr. Lauby has served as chair and is a life member of the International Electricity Research Exchange and served as chair of a number of IEEE working groups. From 1999 to 2007, Mr. Lauby was an appointed member of the Board of Excellent Energy International Co., LTD, an energy service company based in Thailand. He has been recognized for his technical achievements in many technical associations, including the 1992 IEEE Walter Fee Young Engineer of the Year Award. He was named a Fellow by IEEE in November 2011 for "leadership in the development and application of techniques for bulk power system reliability." In 2014, Mr. Lauby was awarded the IEEE Power and Energy Society's Roy Billinton Power System Reliability Award. In 2020, the National Academy of Engineering (NAE) elected Mr. Lauby as a member, citing his development and application of techniques for electric grid reliability analysis. He is also a member of the IEEE Power & Energy Society (PES) Executive Advisory Committee, focused on providing strategic support to the PES Board of

Directors.

Prior to joining NERC, Mr. Lauby worked for the Electric Power Research Institute (EPRI) for 20 years, holding a number of senior positions, including: director, Power Delivery and Markets; managing director, Asia, EPRI International; and manager, Power System Engineering in the Power System Planning and Operations Program. Mr. Lauby began his electric industry career in 1979 at the Mid-Continent Area Power Pool in Minneapolis, Minnesota. His responsibilities included transmission planning, power system reliability assessment, and probabilistic evaluation.

Mr. Lauby is the author of more than 100 technical papers on the subjects of power system reliability, expert systems, transmission system planning, and power system numerical analysis techniques. He earned his bachelor's and master's degrees in Electrical Engineering from the University of Minnesota. In addition, Mr. Lauby attended the London Business School Accelerated Development Program as well as the Executive Leadership Program at Harvard Business School.

Natural Gas & Power Industries' Reliability Alliance:

Exploring Real-Life Challenges with Ensuring Natural Gas Availability for Power and Joint Industry Suggested Mitigation Strategies

INTRODUCTION

Following Winter Storm Elliott, trade associations representing natural gas-fired generators, natural gas suppliers, and interstate pipelines ("the Reliability Alliance") met to explore solutions to the operational challenges to maintaining reliable fuel for power generation.[1] Based on gas generators' experiences, the vast majority of problems occur when both the natural gas and electricity systems are stressed by high demand. During Elliott, most gas generator outages occurred when RTOs/ISOs called generators to run in Real-Time. In fact, PJM found that *nearly 90%* of fuel-related outages happened in the Real-Time Market.[2] Accordingly, the Alliance prioritized Real-Time challenges and identifying ways to better manage gas procurement during extreme events.

The challenges to meeting Real-Time Market dispatches largely occur during extreme weather, but we expect these challenges to become more common as RTOs/ISOs increasingly rely on natural gas-fired generators to dispatch on short notice in response to reduced wind and solar generation. Members of the Reliability Alliance (and nearly all voters in the NAESB Gas-Electric Harmonization Forum[3]) agree that it is important to assess whether this country has sufficient natural gas infrastructure to support the level of real-time flexibility that electric system operators need to respond quickly to intermittent resource fluctuations, such as wind and solar. While this paper primarily focuses on real-time challenges during winter events, the Alliance also acknowledges that policies must support gas infrastructure that is critical for the nation's evolving and diverse generation resources.

This consensus document discusses the challenges with real-time dispatches and hurdles to building gas infrastructure and suggests the following approaches to address unexpected challenges. The Reliability Alliance invites regulators, policymakers, RTOs/ISOs, and other market stakeholders to further discuss these solutions.

---

[1] The Reliability Alliance is composed of the Electric Power Supply Association ("EPSA"), Interstate Natural Gas Association of America ("INGAA"), and Natural Gas Supply Association ("NGSA") and was formed through a series of in-person member meetings that resulted in frank discussions and dialogue among industry providers and power customers that depend on natural gas to run their units. These discussions helped to peel back the layers and the rhetoric often found on both sides to allow us to develop a better understanding of the challenges each industry faces and to prioritize the key challenges to gas-electric coordination that must be overcome to maintain reliable operations. The Reliability Alliance welcomes all gas industry providers and power customers to work together to raise greater awareness and find consensus on the various incremental steps that, when taken together, should provide for significant improvements in the availability of natural gas for power, especially during cold winter events.

[2] See Slide 15 of Presentation from March 9, 2023, PJM Operating Committee Meeting, Winter Storm Elliott Continued Outage Analysis.

[3] See voting matrix for Recommendation 20, *North American Energy Standards Board Gas Electric Harmonization Forum Report*, July 28, 2023 (pp. 63-66).

Real Time Market Challenges:

- Improving Pricing in Power Markets, Especially the Real-Time Market.
- Improving Certainty in Power Markets to Encourage Advance Gas Purchases.
- Considering Ways to Facilitate Gas Purchases During Intra-Day Periods, Weekends, and Holidays.
- Allowing Updates to Generator Offer/Operating Parameters in Real-Time.
- Accounting by RTOs/ISOs for Gas System Limitations in Generator Commitment and Dispatch.
- Considering Enhanced Pipeline Notices and Services to Address Power System Needs.

Gas Infrastructure Challenges:

- Considering ways that generators can financially support investment in gas infrastructure required to serve power demand and increased ramping requirements.
- Developing mechanisms for wholesale electric market participants to anchor additional pipelines.
- Considering whether increasing pipeline capacity is commercially viable as part of complying with new emissions mandates.
- Supporting legislation that removes hurdles in the permitting process and asking FERC to rescind pending draft policies that add uncertainty and investment risk.
- Encouraging RTOs/ISOs and NERC to advocate for specific projects, particularly storage, which will enhance reliability of gas supply and provide flexibility.

1. ADVANCE FUEL PROCUREMENT AND SCHEDULING WITHOUT CERTAINTY OR COMPENSATION. There are two primary types of uncertainty that can deter gas generators from purchasing and scheduling gas in advance of dispatch (for real time, day ahead, monthly, or long-term):

(1) uncertainty regarding how often and when the ISO/RTO will dispatch the generator; and

(2) uncertainty as to whether the generator can recover their fuel cost if not called upon to run.

These uncertainties increase reliability risks in the Real-Time Market when pipeline capacity is constrained and when most gas supply has been purchased. Reliability risks are highest in these circumstances because most entities serving end-users purchase gas in the monthly or Day-Ahead Markets for their weekend (Saturday through Monday) gas requirements and schedule this gas during Friday's Timely Nomination Cycle. As a result of these advance capacity and supply arrangements, there may be less availability and flexibility in the market for meeting generator needs over the weekend. This issue can be further compounded when end-users who otherwise might release gas are unavailable over extended holiday weekends. Moreover, Platts does not publish price indices for individual weekend days due to lower liquidity, so generators typically must enter into fixed price transactions with suppliers or use ICE to acquire a single day or intra-day purchase. Prices typically will reflect scarcity in critical periods. For these reasons, generators must be able to procure their gas needs as early as possible.

POTENTIAL IMPROVEMENTS:

A. Improve Pricing in Power Markets, Especially the Real-Time Market.

i. Develop market-based mechanisms to better signal expected power dispatch, avoid uplift, and include fuel costs to reflect the cost of reliability in the market price. These mechanisms would encourage advanced gas procurement with less risk of unused supply, more timely pipeline nominations, and the ability to purchase fuel in more liquid periods. The development of market-based solutions—such new energy/ancillary service products or more robust reserve requirements—should be the first line of focus.

ii. *In the absence of market-based solutions*, consider the need for last resort backstop mechanisms that would cover net losses from advanced gas purchases in limited, critical event circumstances. These mechanisms would limit potential cost shifting on load because early procurement reduces risk of purchases in most volatile (and expensive) periods during critical events (to be defined) and increases the reliability for load as "insurance." Possible mechanisms for consideration include:

   a. Multi-day clearing mechanisms that, following issuance of a cold weather alert by ISO/RTO based on objective criteria (to be defined), compensate generators for net losses (and offset net profits) from advance gas purchases necessary to allow these generators to be "on call" during the alert. Mitigation must reflect generators' increased risk for multi-day scheduling and fuel procurement.

   b. Increased certainty that a generator will be made whole when not cleared in the Day-Ahead Market but then called upon to run during critical events and thus procuring gas for the remainder of the 24-hour gas day or pursuant to a generator's contractual ratable commitment based on the timing of the gas day.

B. Improve Certainty in Power Markets to Encourage Advance Gas Purchases.

i. RTOs/ISOs should notify generators as early as possible of the need to run (or at least the need to be prepared to run). Early notification allows a generator to procure gas supply when the market is sufficiently liquid and schedule gas transportation pursuant to the NAESB Timely Gas Day timeline. This could include multi-day clearing as noted in A above.

ii. Shift the start time of regional Power Days to better align with the existing national standard Gas Day, which (1) reduces the need for intra-day gas purchases and intra-day pipeline nominations, (2) limits pipeline imbalances, and (3) allows generators to address their evening power peak or calls to run late in the day/night.

a. If necessary, evaluate changes to the Gas Day after implementing changes to the Power Day.

iii. RTOs/ISOs should reconcile their forecasts and load bids in the Day-Ahead Market and fill any gap with supplemental market-based merit order clearing as soon as possible to reduce calls on generation in Real-Time.

a. To improve the operator's ability to forecast and dispatch sufficient resources in the Day-Ahead Market, our groups would like to work with RTOs/ISOs to identify more opportunities for information sharing, where sharing is practical, and adds value for situational awareness, and appropriately protects sensitive data.

b. As recommended in the NAESB Forum, RTOs/ISOs might also improve visibility into gas industry conditions once Argonne's tools are in place to provide near real-time data, though data access and reliance issues need to be addressed.

c. RTOs/ISOs may also want to expand the scope of their forecasting assessments to include an examination of the forecast models used by other gas users in their region, such as LDCs.

C. Consider Ways to Facilitate Gas Purchases During Intra-Day Periods, Weekends and Holidays.

i. Advocate for standardized postings on ICE for single-day options instead of only reflecting 3- or 4-day weekend strips. While this option already exists as a customizable option, single day options on the initial screen may encourage parties to consider these options.

ii. Promote the development of daily indices for individual weekend days with index publishers. Such a single day index may encourage more market participation and liquidity on weekends and holidays. Until then, the prevailing prices on ICE during weekend events should be considered the best measure of single day weekend pricing.

iii. Encourage generators to expand their pool of suppliers by (1) entering into credit/collateral approvals with many gas sellers on ICE or (2) obtaining pre-approvals for transactions with a diverse set of suppliers that they can contact directly, especially during weekends and holidays.

iv. Incentivize pipeline firm shippers to post excess capacity as soon as possible or to enter into AMAs that maximize efficient use of shippers' capacity. Support state policies that encourage LDCs to take these actions, although it is unlikely that LDCs will release any substantial amounts of their firm reserved capacity during critical events.

2. REAL-TIME DISPATCH REQUIREMENTS CONFLICT WITH NAESB TIMEFRAMES FOR GAS FLOW OR RATABLE TAKES THAT ARE ENFORCED DURING CRITICAL PERIODS. The existing NAESB timeline recognizes that there must be sufficient time to match flows with nominated volumes. Some pipelines provide services that allow for nominations outside the NAESB timeline while others use best-efforts to accommodate shippers' needs for flexibility. But the time to balance a system makes it difficult to formally compress the time between nominations and flows.

While best-efforts flexibility is more available during normal operating conditions, during critical periods, pipelines may not have the operational flexibility to enable generators to meet unexpected Real-Time dispatches (that require a generator to run in 30 minutes or less) by flowing gas outside NAESB cycles or by allowing non-ratable flows, regardless of contract. When considering its commitments to the RTO and the gas tariff restrictions, generators are left in an untenable position. Inaccurate power demand forecasting will exacerbate this problem by not clearing sufficient resources for reliability in the Day-Ahead Market, which would allow generators to arrange fuel supply in a timely manner.

Generators' operating parameters are much more limited when a pipeline has issued an Operational Flow Order (OFO) and gas supply and pipeline capacity is not readily available. Therefore, it is critical that generators have the ability to revise their parameters in their energy market must-offer bids during the Real-Time Market—supported by documentation from pipelines—to reflect changing gas market conditions and to provide the RTO/ISO with advance notice of their operating limitations.

POTENTIAL IMPROVEMENTS:

A. **Allow Updates to Operating Parameters in Real-Time.** RTOs/ISOs should allow generators to update their operating parameters in the Real-Time Market to reflect gas system limitations. Stakeholders must resolve whether current FERC rules permit this practice. Generators should be allowed to update their operating parameters as soon as possible when pipelines impose restrictions that impact the typical flexibility afforded to the unit.

B. **Consider Enhanced Pipeline Notices and Services to Address Power System Needs.**

  i. Encourage more pipelines to accept nominations after ID3 on a "best efforts" basis when the generator has procured gas supply and capacity is available. Explore how to provide these opportunities even when an OFO has been issued.
  ii. Ensure pipeline notices, such OFOs, are clear and provided as far in advance as possible for gas generators to justify/support real time offer parameter changes to the RTO/ISO.
  iii. To the extent possible using existing infrastructure, pipelines should be encouraged to design enhanced services that (1) align/match power market usage patterns, (2) do not require 365-day ratable use, and (3) do not put costs on other shippers.
  iv. Pipelines should review what incremental infrastructure would be required to offer more no-notice or non-ratable services and develop a rough estimate of the costs so that regional operators, generators, and regulators have a general idea of what they would need to pay to have these services.

3. ORGANIZED POWER MARKETS DO NOT SUPPORT THE LONG-TERM COMMITMENTS NEEDED TO EXPAND GAS INFRASTRUCTURE. RTO/ISO market design often does not incentivize generators to make the long-term commitments that can support the development of additional pipeline capacity. Constant changes, reevaluations and out-of-market actions have created instability in capacity markets that have eroded the certainty that it was intended to provide to generators. RTOs/ISOs should study and FERC should convene a workshop to explore ways for wholesale electric market participants to anchor additional pipeline infrastructure. Also, pipelines should consider if capacity increases are commercially viable when they undertake required upgrades to comply with new emissions mandates.

4. INFRASTRUCTURE PERMITTING DELAYS. Unduly burdensome permitting processes and protracted litigation increase investment risk and obstruct or delay natural gas infrastructure expansion.

POTENTIAL IMPROVEMENTS:

A. **Support Legislation that Removes Hurdles in the Pipeline Permitting Process and Ask FERC to Rescind Pending Draft Policies that Add Uncertainty and Investment Risk.**

B. **Encourage RTOs/ISOs and NERC to Advocate for Specific Gas Infrastructure Projects, Particularly Storage, that Enhance Reliability of Gas Supply and Provide Increased Flexibility.** The coalition study that asks DOE to look at whether there is sufficient natural gas infrastructure to support fuel availability for ramping may be helpful to pinpoint where such needs exist.

Cloud Technology Panel

Action
Review

Background
As more cloud computing technologies emerge and vendors offer cloud solutions to the electric sector, there will be an increase in utilities on the Bulk Electric System exploring these new technologies. It is apparent there will be an impact to BES operations. However, utilities should carefully assess security and reliability risks of migrating systems and applications to the cloud. This technical panel will provide a broad overview on cloud technology and some of the associated risks and benefits. Additionally, this panel will touch on regulatory issues that may impact the industry in the near future.

Matthew G. Hyatt, Director, Power Technology Operations
Matt Hyatt has a technical and leadership background in Information Technology, Telecommunications, Power Control Systems, and Cyber Security. Over the past 16 years, Matt has worked primarily on increasing the Resiliency and Cyber Security of OT systems that support the Power Grid. Matt spent 14 years serving the federal government sector for Tennessee Valley Authority and now serves Georgia System Operations who centrally operates for the co-operative utilities in Georgia. He also serves as co-chair of the 2016-02 NERC CIP Standards Drafting team working on a project to incorporate concepts for virtualization and future technologies, such as those that support Zero Trust methodology, into the NERC CIP Standards for Utilities.

Rudolf “Rudy” Pawul, Vice President, Information and Cyber Security Services

As Vice President, Information and Cyber Security Services, Rudolf “Rudy” Pawul is responsible for ISO New England’s information technology (IT) functions and cyber security program. Mr. Pawul came to ISO New England in 1999 as a UNIX system administrator, joining the company at the same time the region’s first wholesale power markets were launched. In his tenure, he has held a variety of roles of increasing scope and responsibility, including manager of Systems Support and IT Director, Infrastructure and Enterprise Support. Most recently, as IT Director of Development of Power System Support, he was in charge of the 24 x 7 energy management and markets systems for the New England region.

Rudy holds a Bachelor’s degree in electrical engineering from Union College and earned his Master’s degree in electrical engineering at the Microwave Remote Sensing Laboratory of the University of Massachusetts. He received his Master of Business Administration from Western New England College.

Interregional Transfer Capability Study (ITCS)

Action

Update

Background

Congress passed the Fiscal Responsibility Act of 2023, which included a provision for NERC to conduct a study on the reliable transfer of electric power between neighboring transmission planning areas. NERC, in consultation with the Regional Entities and industry stakeholders, will conduct transfer capability studies for regional transmission areas in the United States and recommend prudent additions to transfer capability needed for reliability.

Who: NERC, in consultation with each regional entity and each transmitting utility[1] in a neighboring transmission planning region.

What: A study of total transfer capability between transmission planning regions.[2] In accomplishing this work, the study should include:

1. "Current total transfer capability, between each pair of neighboring transmission planning regions."[3] [4]
2. "A recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions"; and
3. "Recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions."

When: NERC must file the report with FERC within 18 months of enactment of the bill. Public comment period will occur when FERC publishes the study in the Federal Register. After submittal, FERC must provide a report to Congress within 12 months of closure of the public comment period with recommendations (if any) for statutory changes.

ERO study filing deadline: On or before December 2, 2024

---

[1] "means an entity (including an entity described in section 201(f)) that owns, operates, or controls facilities used for the transmission of electric energy—(A) in interstate commerce; (B) for the sale of electric energy at wholesale." [FPA, Section 3(23)]

[2] (a) IN GENERAL.—The Electric Reliability Organization (as that term is defined in section 215(a)(2) of the Federal Power Act), in consultation with each regional entity (as that term is defined in section 215(a)(7) of such Act) and each transmitting utility (as that term is defined in section 3(23) of such Act) that has facilities interconnected with a transmitting utility in a neighboring transmission planning region, shall conduct a study of total transfer capability as defined in section 37.6(b)(1)(vi) of title 18, Code of Federal Regulations, between transmission planning regions that contains the following:" [1-3 bullets quoted above]

[3] **Total transfer capability** means the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards. [18 C.F.R. Section 37.6(b)(1)(vi)]

[4] **Neighboring transmission planning region**: implicitly means facilities connecting two adjacent systems or control areas.

Key Activities

- **Framework**
  An industry Advisory Group was formed to seek active industry input on the technical approach being used to perform the work and preparation of final report. The Advisory Group convened its first meeting on October 31. The ITCS Project Team provided members with an overview of the study requirements detailed in the Fiscal Responsibility Act, discussed roles and responsibilities, and highlighted key input areas and timelines. One of the first priorities for the Advisory Group was a review and comment period of the draft ITCS Framework. Comments, which were discussed at the November 28 Advisory Group meeting, were grouped by theme in seven categories: transfer capability assumptions and considerations; clarifying study scope; modeling and metrics; base case/extreme scenario commentary; clarifying study timing; inclusion of Canadian regulators/ regions; and others. Comments have been used to inform the final Framework document. The Advisory Group represents diverse industry expertise across regional transmission planning areas in North America, including representatives from stakeholders in each Regional Entity footprint and Canada.

- **Scoping Documents**
  The ITCS Project Team developed two draft scoping documents to address the transfer capability analysis and to document an approach to determine prudent additions to transfer capability, referred to in the ITCS timeline as Part I and Part II. This includes case and scenario development; production, dispatch and energy adequacy analysis; and transfer analysis. This is a work in progress, and the approach continues to be refined. The two scoping documents have been posted for Advisory Group feedback. Finalized scoping documents are expected to be completed by January 31.

- **Data Request**
  The Project Team, comprised of NERC and the Regional Entities, developed a data request that was sent to industry last year in November. The requested data will be used to update MOD032 base cases with the most up-to-date information on transmission topology, loads, resource forecasts, etc., for the Western and Eastern Interconnections. The deadline for industry to respond to this Section 800 data request is January 17, 2024.

  Another data request has been sent to some of the entities for the required energy data for determining prudent additions to transfer capability. The deadline for industry to respond is February 19, 2024.

- **Stakeholder Outreach**
  The ERO Enterprise (NERC and the Regional Entities) developed a comprehensive stakeholder outreach plan to ensure that all North American transmitting utilities are able to provide input into the ITCS. Regional Entities are already working with their technical committees, which will continue throughout 2024. The study directive in Fiscal Responsibility Act requires that NERC perform the ITCS in consultation with all transmitting utilities that have facilities interconnected with a transmitting utility in a neighboring transmission planning region.

Next Steps

The Advisory Group’s next meeting is scheduled for January 25 at NERC’s office in Washington, D.C. The in-person meeting will allow for more in-depth discussion on topics including the review of Part I: Transfer Analysis and Part II: Prudent Additions to Transfer Capability approach and assumptions. There will also be a virtual option. The Advisory Group’s meeting schedule has been set throughout the lifecycle of the project.

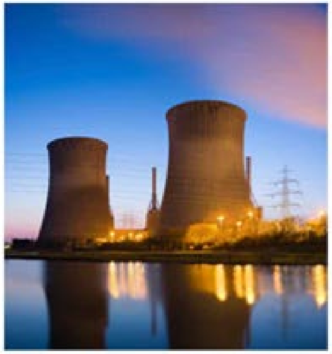
The completion of the ITCS Framework and scoping documents for Part I and Part II of ITCS marks the end of Phase 0: Study Preparation. Phase 1: Analysis begins in the first quarter of 2024 and is scheduled to be completed in July 2024.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interregional Transfer Capability Study

John Moura, Director, Reliability Assessment and Performance Analysis
NERC Quarterly Technical Session
February 14, 2024

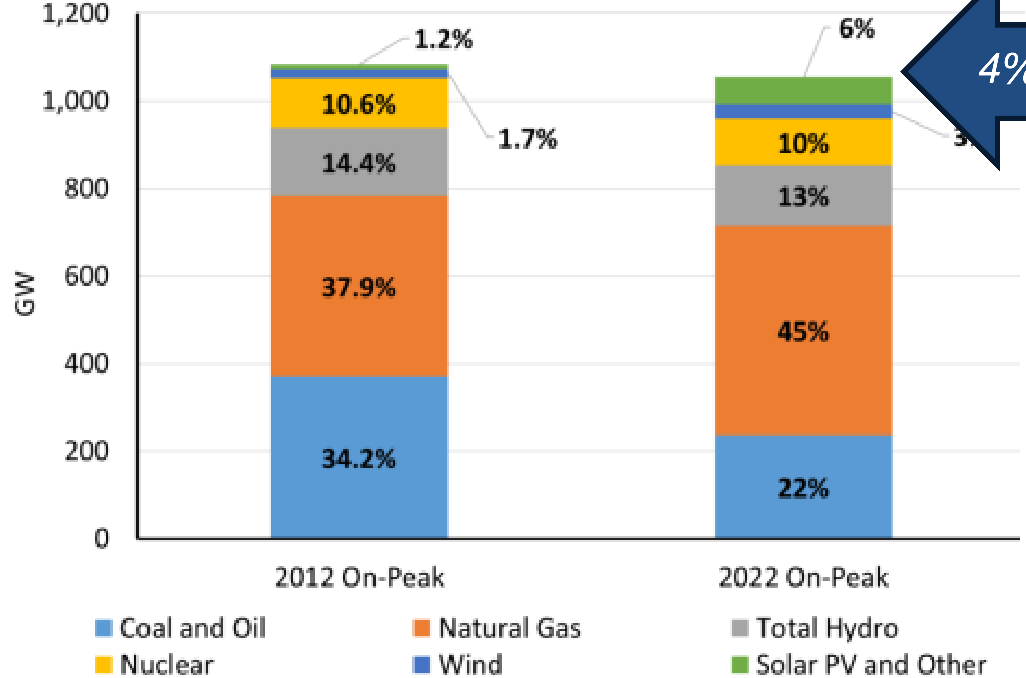
RELIABILITY | RESILIENCE | SECURITY

Across an Interconnected System: Less Resources, More Reliance on Neighbors

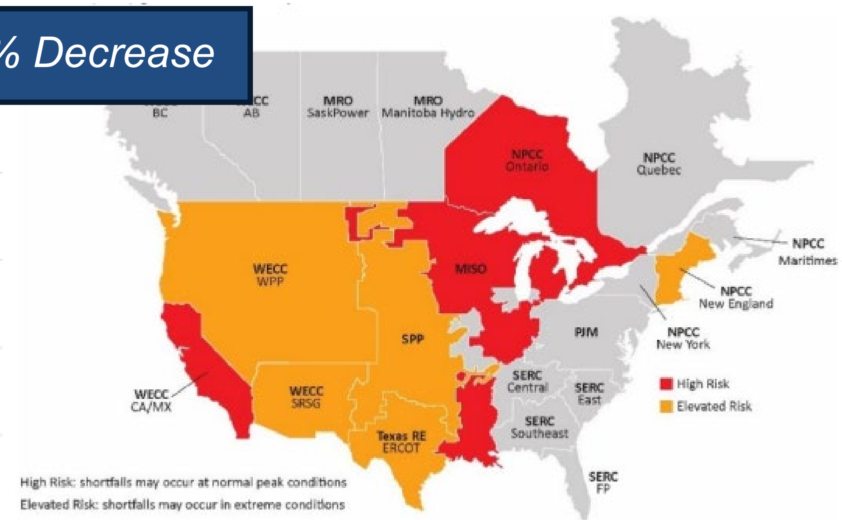
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2012 and 2022 Peak Capacity Resource Mix NERC-Wide

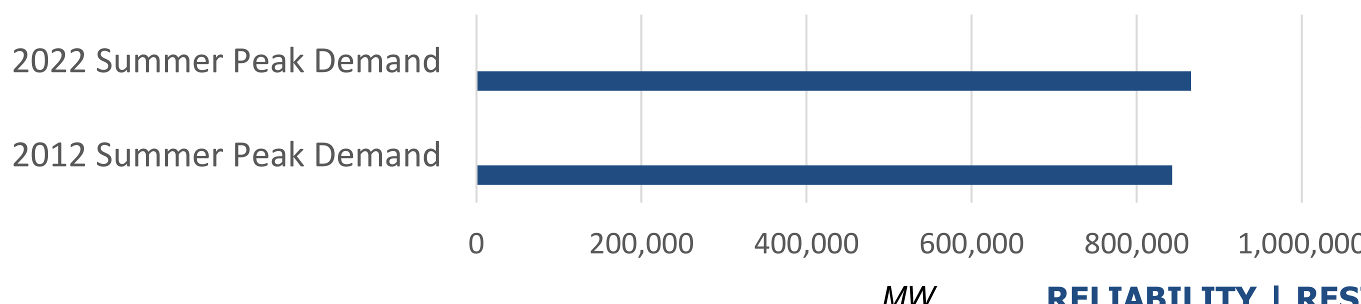


4% Decrease

2025 Risk Areas

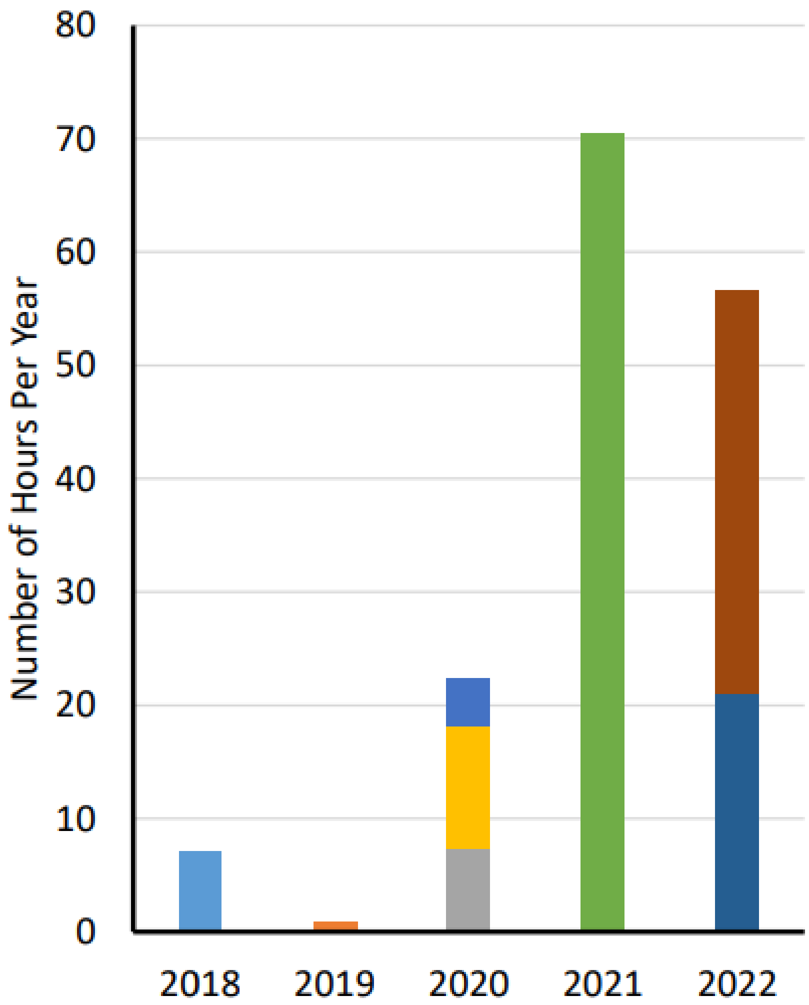


NERC-Wide Summer Peak Demand Changes 2012 and 2022



3% Increase

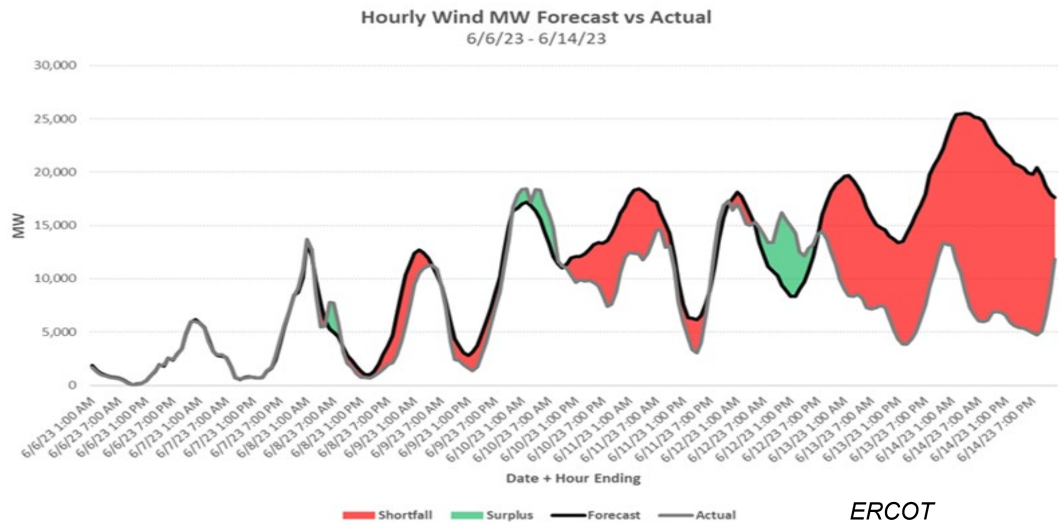
Hours With Operator-Initiated Firm Load Shed

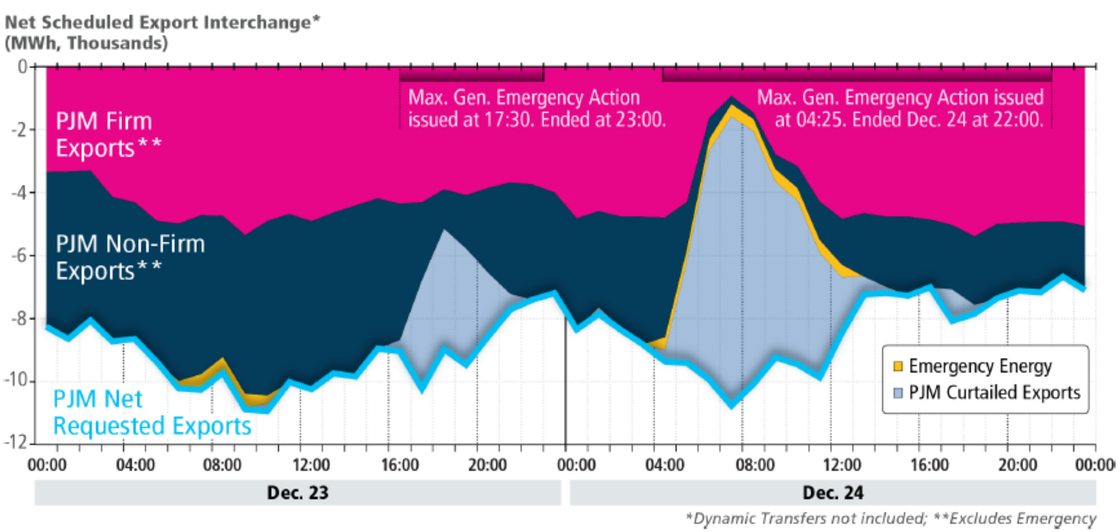


- Winter Storm Elliot (35.52 hours)
- June heatwave (21.01 hours)
- February Cold Weather Event (70.5 hours)
- California Wildfires (4.1 hours)
- Hurricane Laura (10.9 hours)
- California Heatwave (7.4 Hours)
- Western Interconnection: Generator Trip and Subsequent Failure of Dispatched Units (0.8 Hours)
- Eastern Interconnection: Weather-Related Loss of Transmission lines (7.1 hours)

Recent Examples Highlight Need for Wide-Area Energy Assessments

ERCOT, SPP, MISO: *A "wind drought" caused 60,000 MW of installed wind capacity to generate 300 MW*





PJM: *Transmission system during extreme cold weather limited the ability to export to support southern neighbors*

Long-Term Challenges Emerge

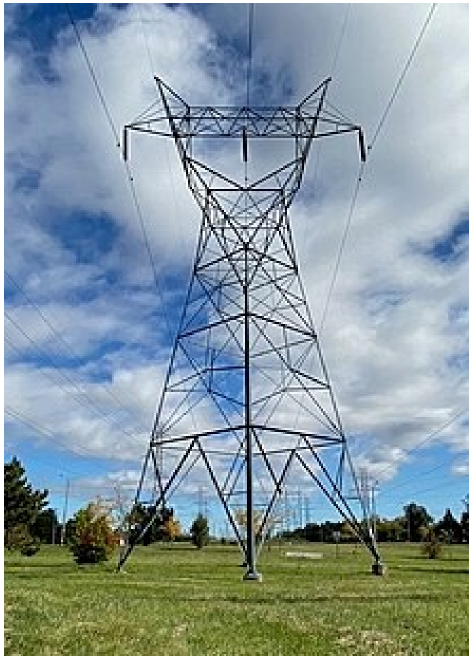
How are we going to integrate…

400,000 MW of Solar

250,000 MW of Wind

80,000 MW of DER

70,000 MW of Batteries



without more of this….

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ITCS Objectives

ITCS aligns with ERO's obligations to perform reliability assessments:

- Independent and objective
- System-wide perspective
- Reliability focus
- Collaboration and coordination
- Strategic planning
- Repeatable process

ITCS Component Requirements

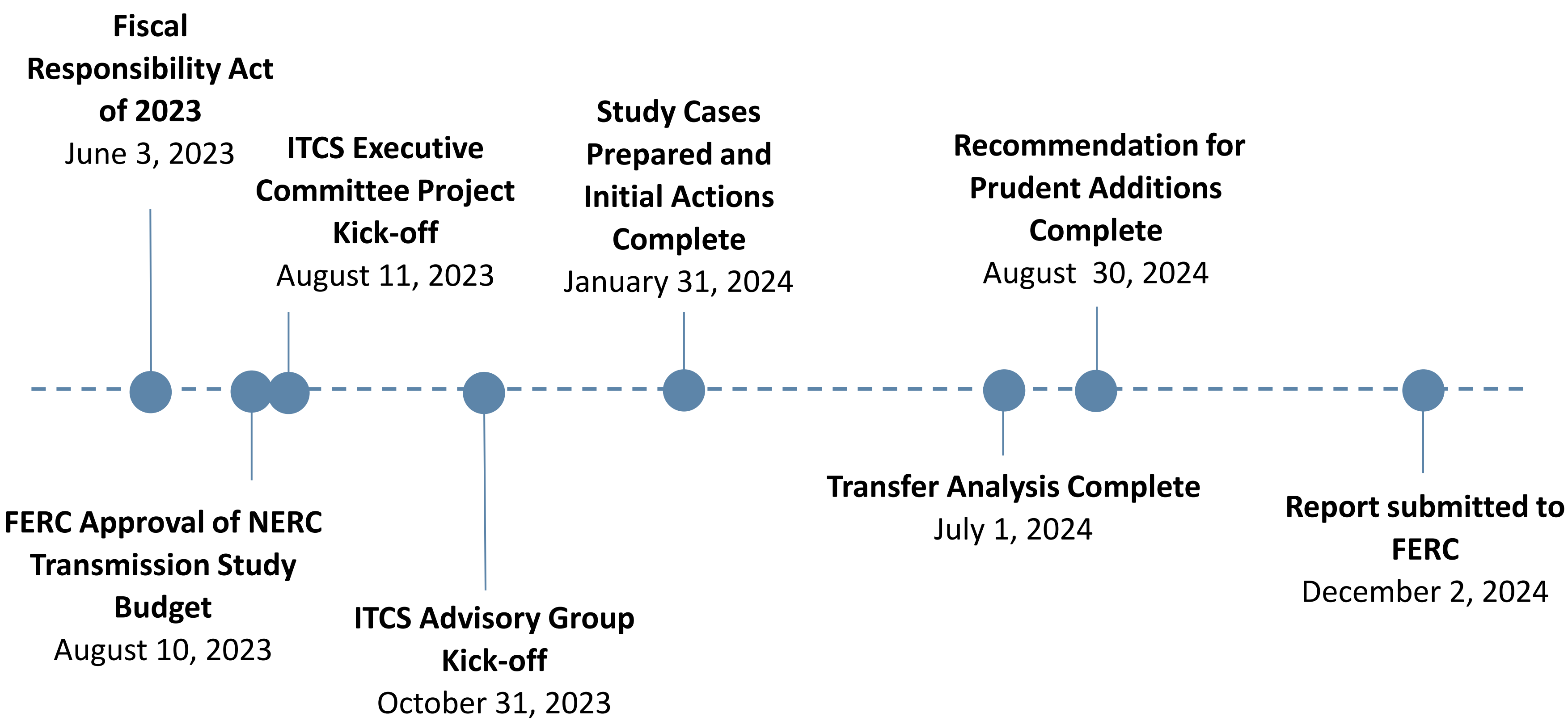
Part-I Current transfer capability

Part-II Recommendations of prudent additions to transfer capability

Part-III Recommendations to meet and maintain transfer capability

ITCS Timeline Overview

The following is a timeline of upcoming key activities:

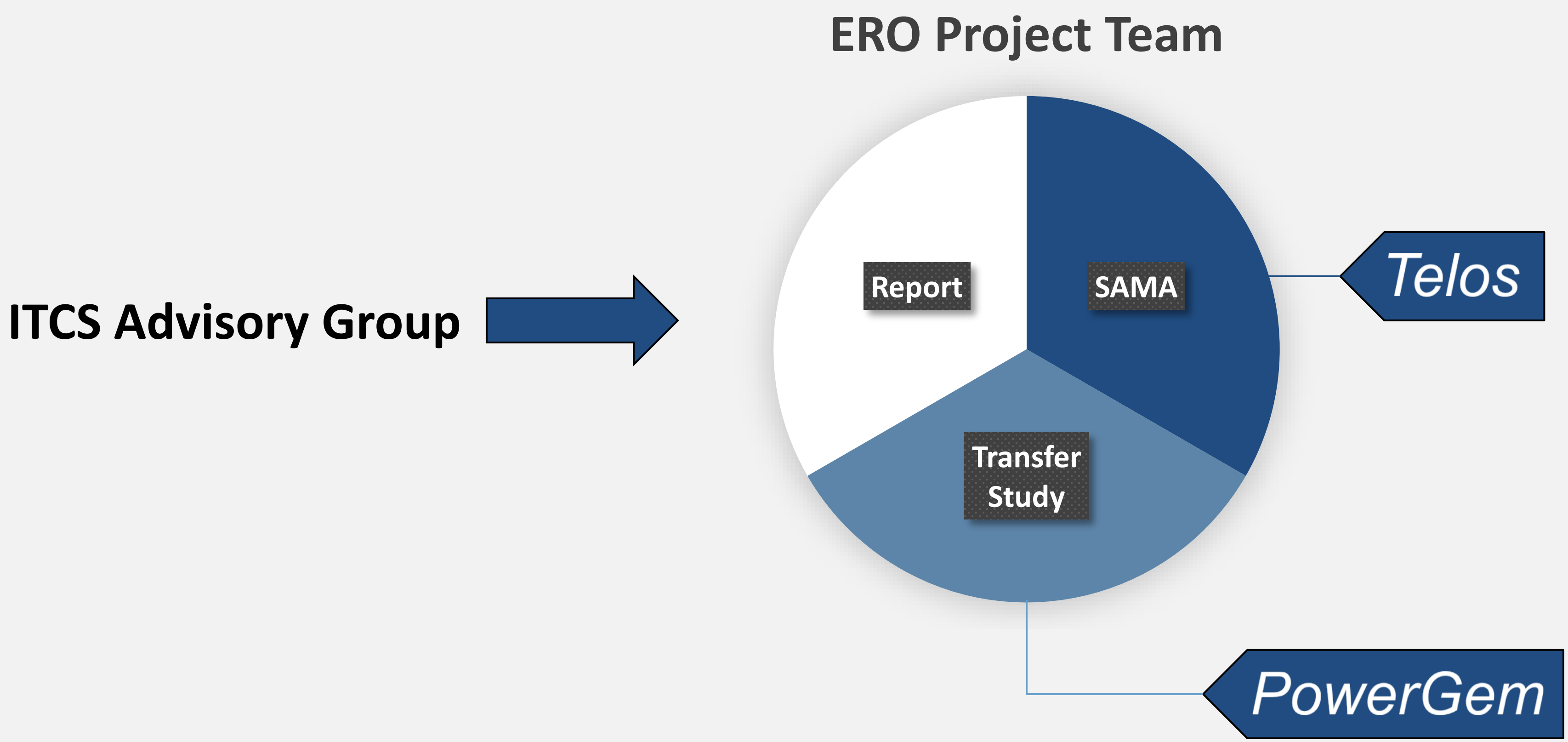


What This Study is NOT

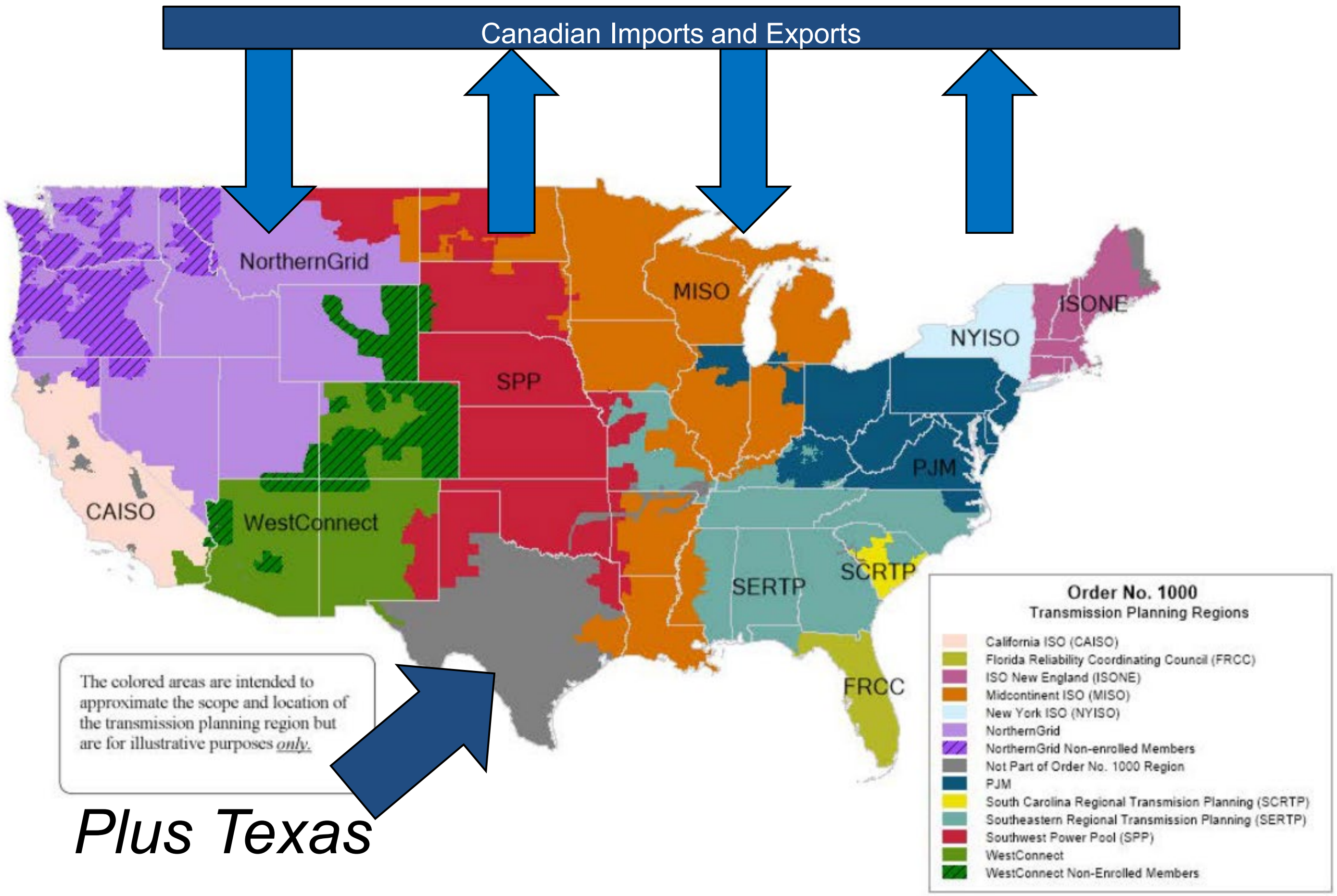
- Planning Study
- Replacement for Transmission Expansion Analysis and Interregional Planning Groups
- No recommendations for specific projections (generation, transmission, etc.)
- Will focus on WHAT…not HOW
- A complete solution

Project Execution Strategy

ERO Executive Leadership Group

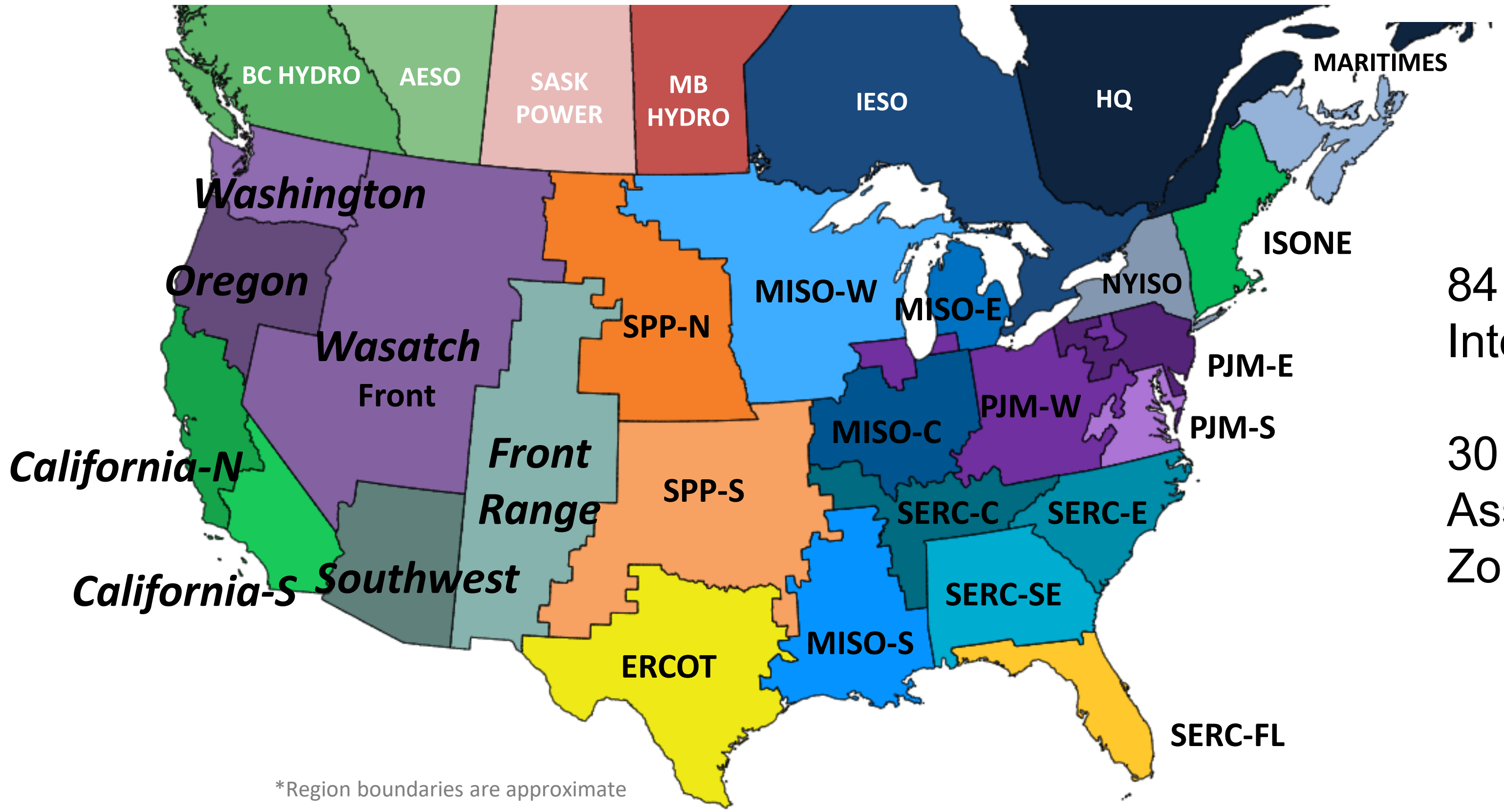


ITCS - Areas of Study



- Legislation identified “Transmission Planning Regions” as identified in FERC Order 1000
- Texas Interconnection DC Ties included
- Canadian transfer capability and possible increases also assessed

Source—Sink Combinations



84 Bi-Directional Interfaces

30 Energy Assessment Zones

Stakeholder Engagement, Outreach, and Coordination

- Quarterly Updates
- ITCS Advisory Group
- Regional Entity technical groups
- State and Federal government organizations
- Various industry/trade groups
- Website
- TO/TOP/TP/PC Outreach

Actions Completed

- Study framework and detailed study scope
- Industry Advisory Group established and currently receiving input and guidance
- DOE knowledge transfer from GDO and Labs
- Canadian strategy for province-to-province evaluation
- Source/Sink combinations finalized and power flow assumptions confirmed, base cases and scenarios being determined
- Regional technical groups established and initial data request being addressed
- “Prudent” criteria for additional transfer capability being tested

Onward!

- Strong transmission system is crucial to a reliable supply and the delivery of electricity
- NERC's role as the independent voice for reliability
- Critical assignment supporting the ERO's Reliability Assessment mandate
- Rapidly changing resource mix requires greater access and deliverability of resources

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Questions and Answers

Bulk Power System Awareness

Action
Update

Background
NERC's Bulk Power System Awareness (BPSA) group acquires and disseminates timely, accurate, and complete information regarding the current status of the bulk power system (BPS) and threats to its reliable operation, to enable the ERO Enterprise to effectively assure the reliability of the BPS. During major system disturbances, extreme weather, fires, hurricanes, physical events, and geomagnetic disturbances, etc. the BPSA facilitates effective communications between the ERO Enterprise, industry, and government stakeholders.

NERC BPSA, in collaboration with the E-ISAC and the ERO Enterprise Situation Awareness teams, maintains a near real-time situation awareness of conditions on the BPS. Notifies the Industry of significant BPS events that have occurred in one area, and which have the potential to impact reliability in other areas. Maintains and strengthens high-level communications, coordination, and cooperation with governments and government agencies regarding real-time conditions.

Bulk Power System Awareness

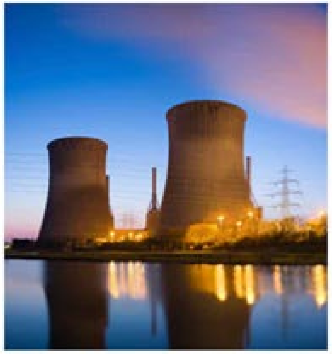
Situational Awareness Q1 2024

Darrell Moore, Director Situation Awareness and Personnel Certification/Credential Maintenance, NERC

NERC Quarterly Technical Session

February 14, 2024

RELIABILITY | RESILIENCE | SECURITY

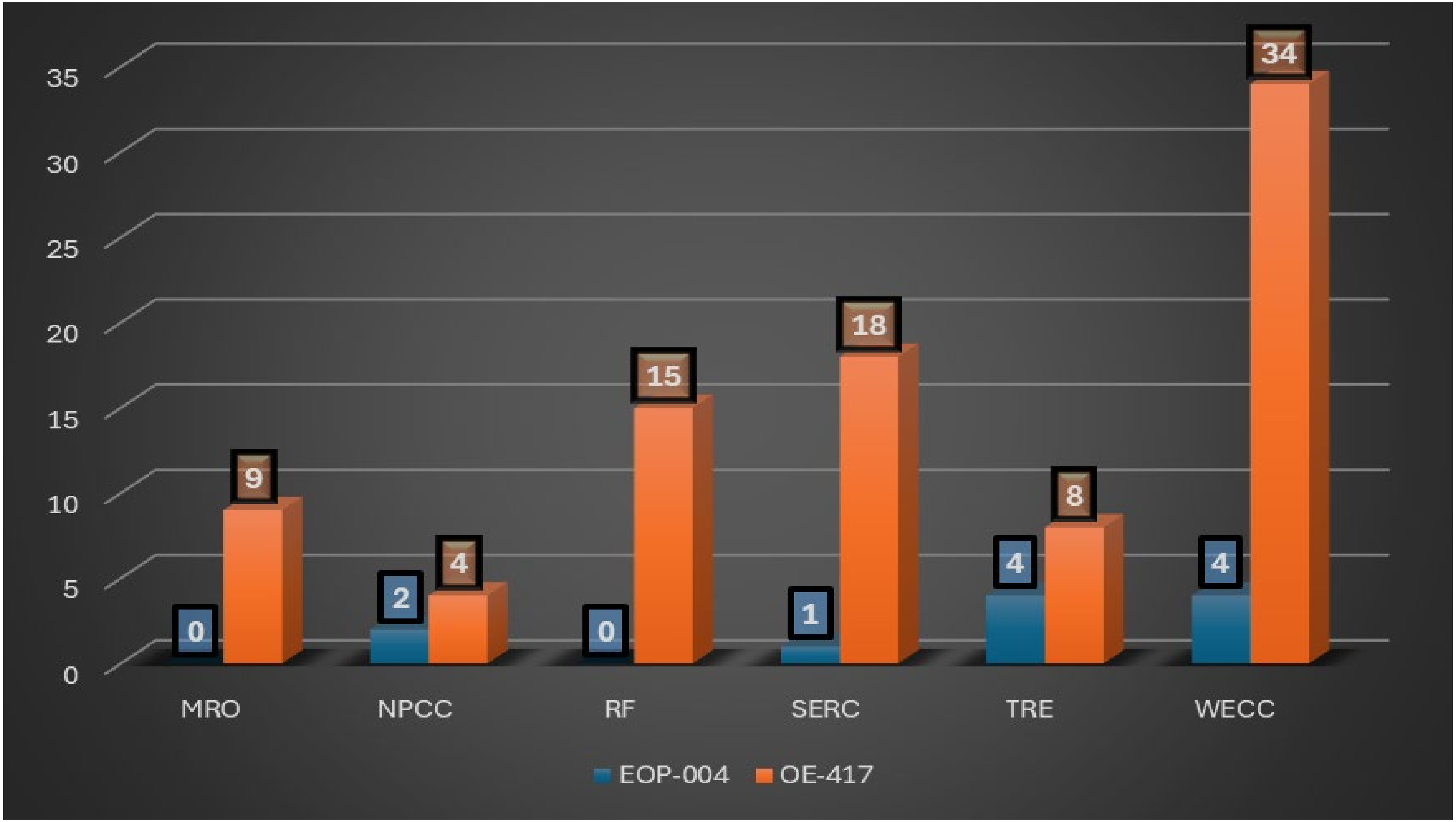



2023 Q4 Overview

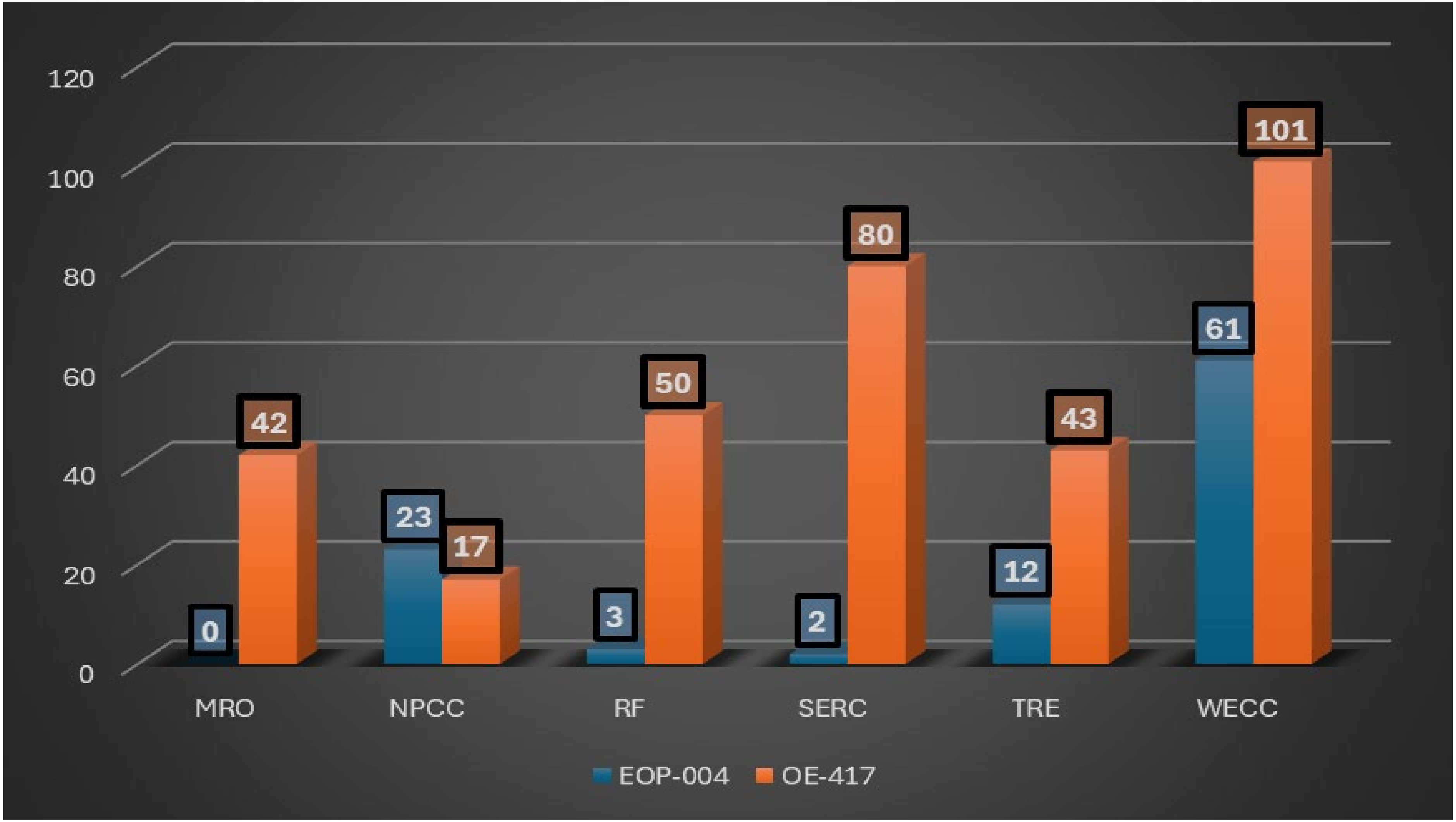
For the fourth quarter of 2023 no widespread significant events were observed or reported on the North American bulk power system (BPS)

- October 6 – Tropical Storm Philippe impacted New England and Atlantic Canada, no significant impacts to the BPS
- October 14 – Annular solar eclipse, no reported or observed impacts to the BPS
- December 18 – A strong storm system delivered heavy rain and strong winds across the Mid-Atlantic, Northeast, and Eastern Canada. At the storms peak, 1.2 million customers were out of service. The BPS remained stable and largely unaffected throughout this event

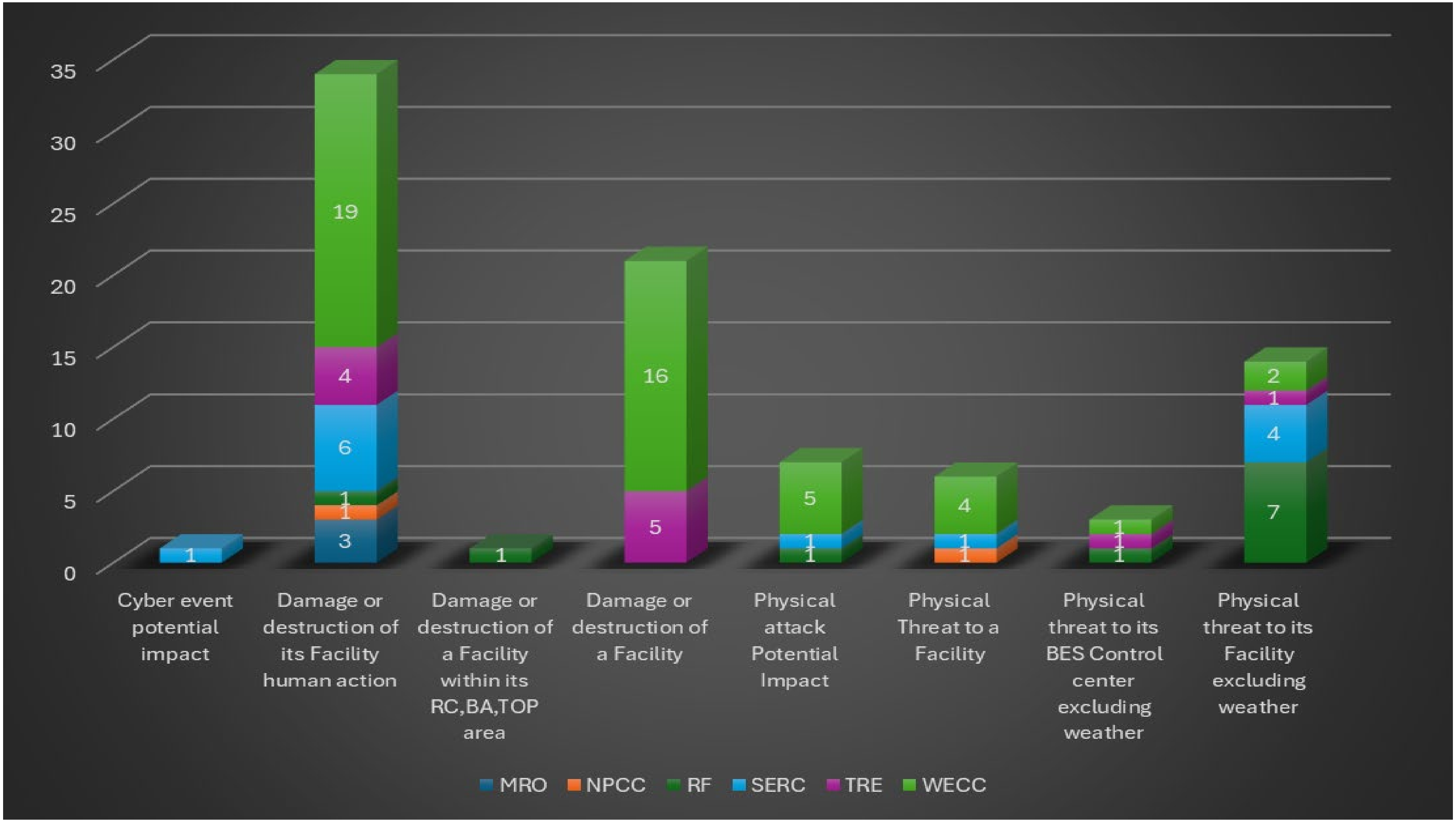
2023 Q4 Mandatory Reports by Region



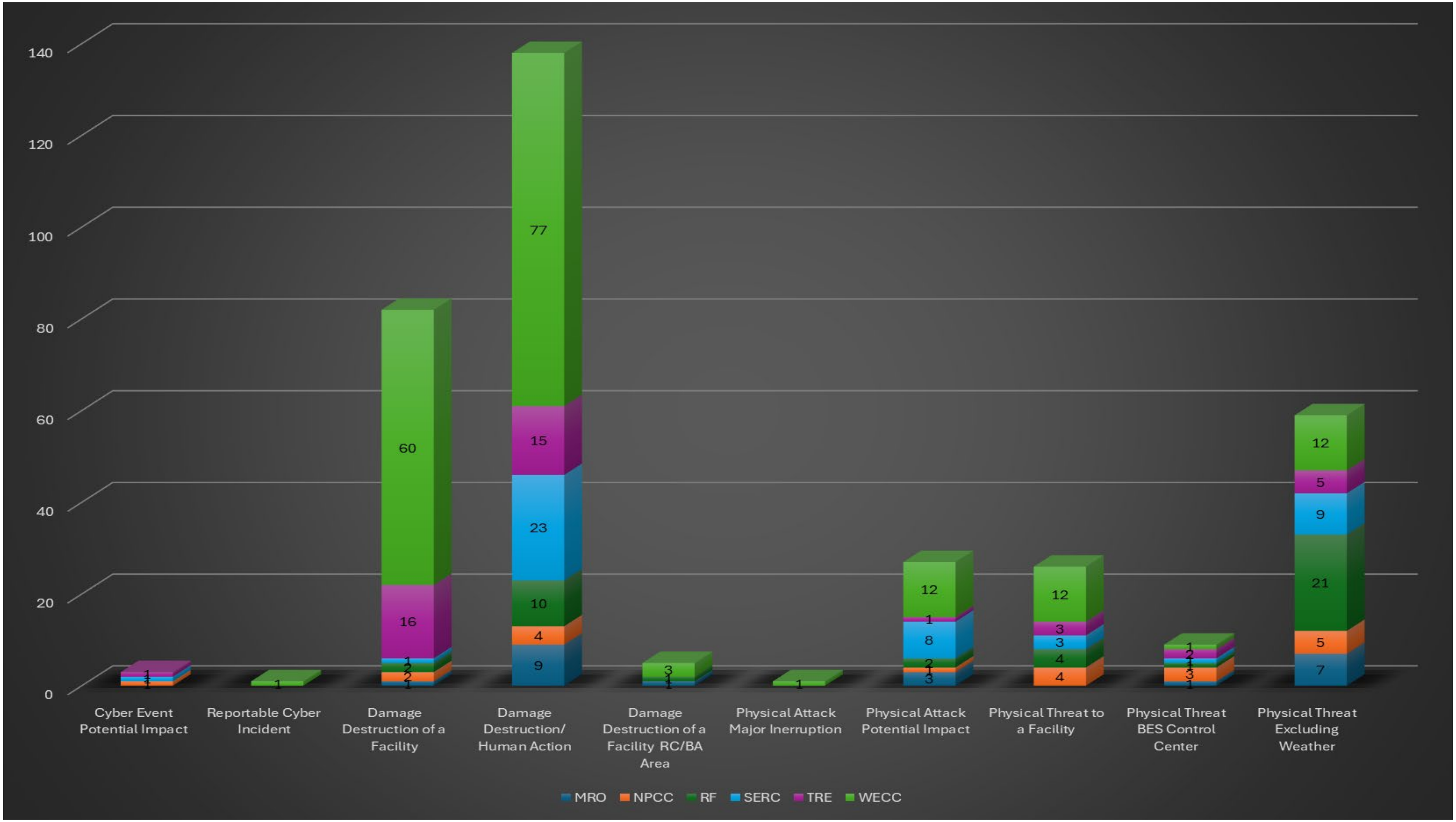
2023 YTD Mandatory Reports by Region



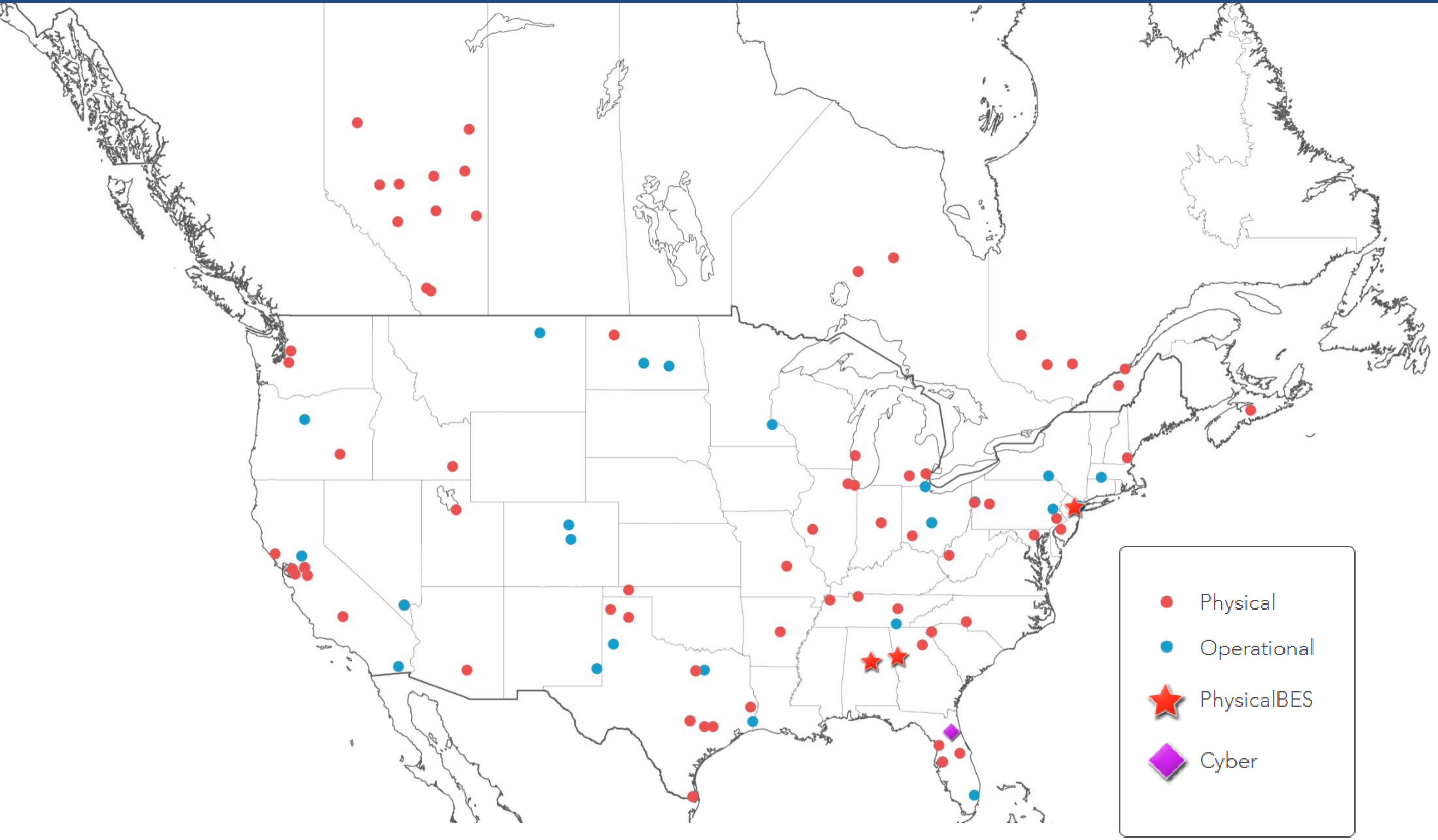
2023 Q4 Cyber & Physical Security Reports by Region



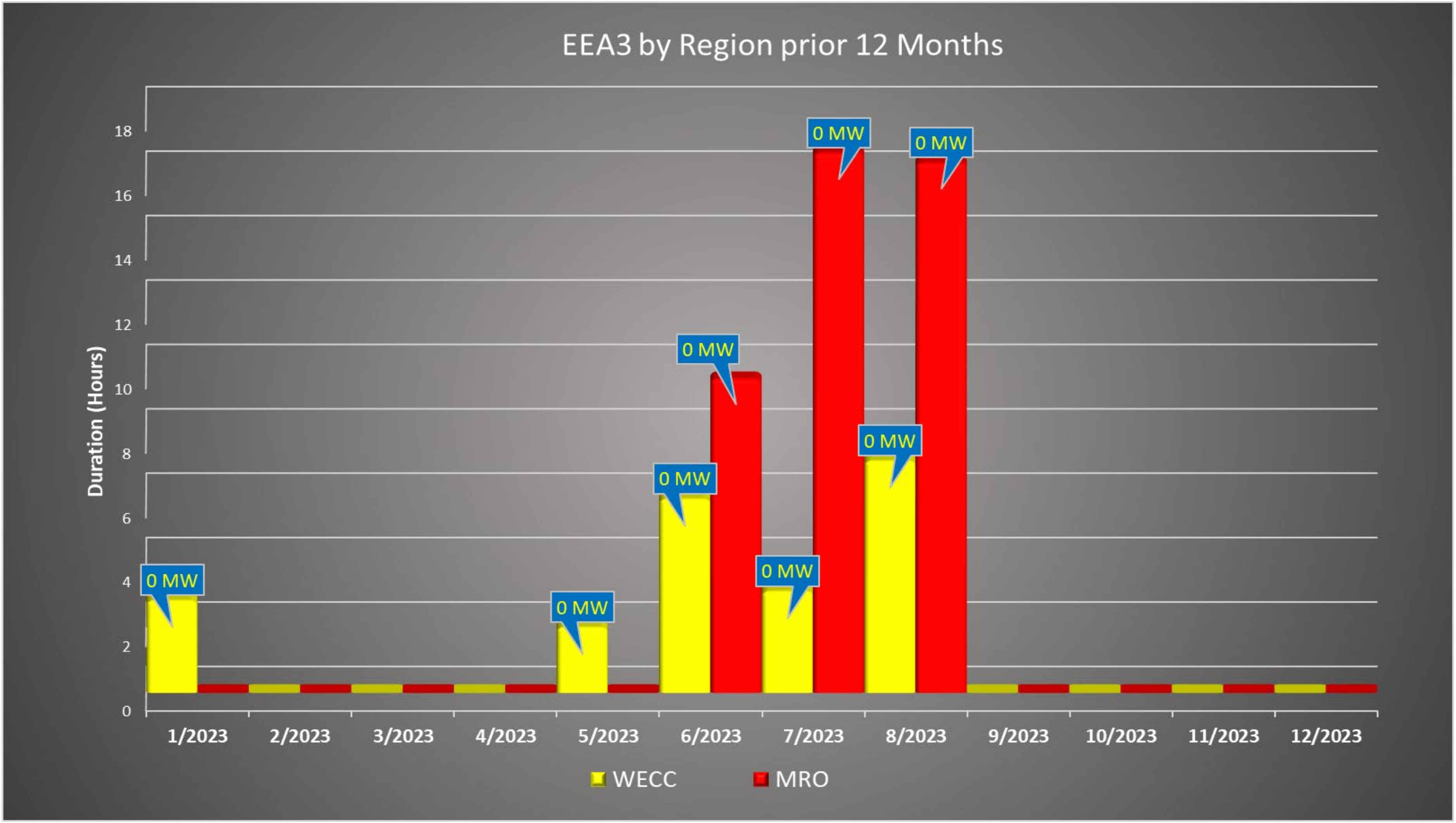
YTD Cyber and Physical Security Reports by Region



2023 Q4 Events
United States & Canada

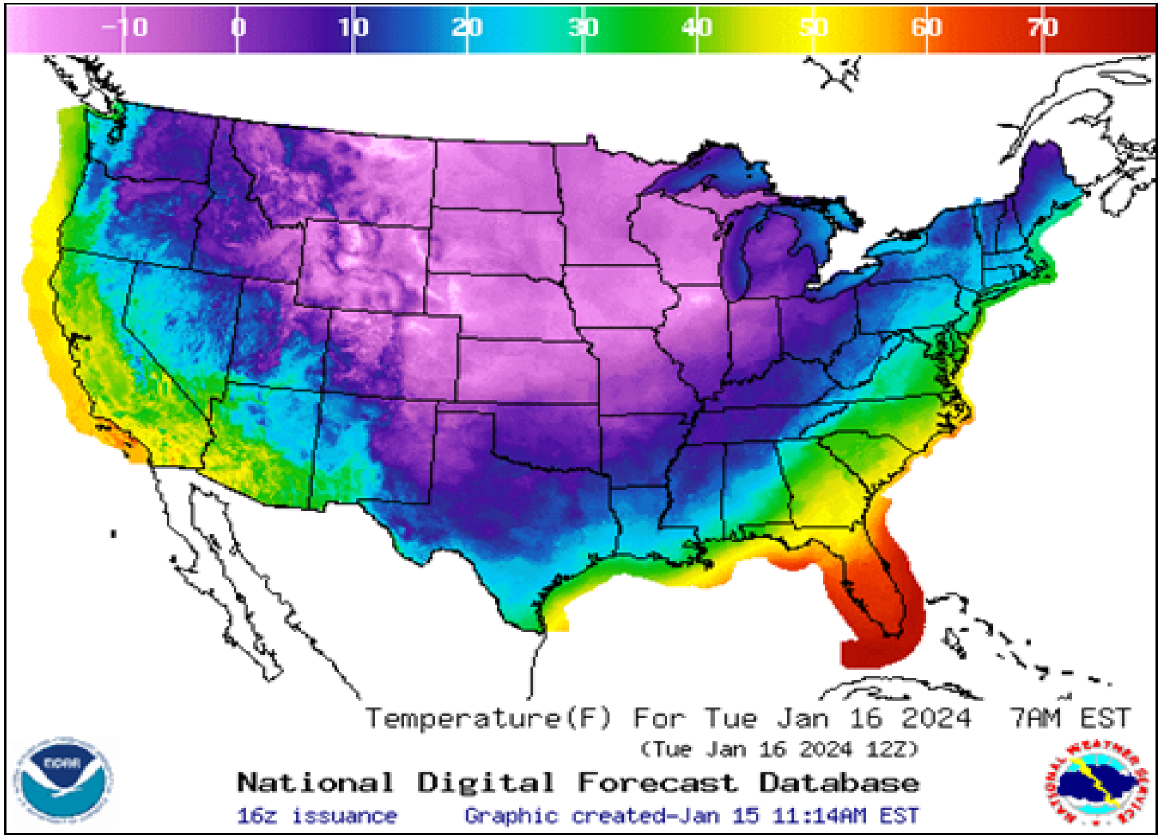


Energy Emergency Alert (EEA) 3 Reports 12 Month View



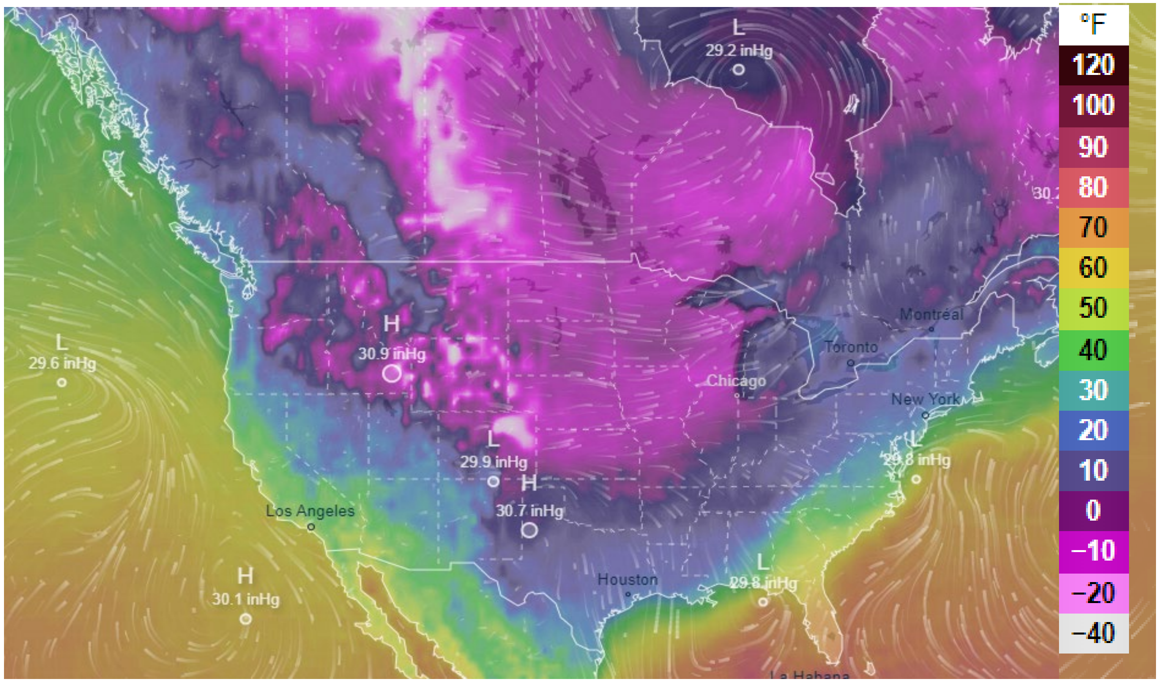
“Hot off the press” January Arctic Cold

- During the month of January, the BPS remained stable as arctic cold, impacted much of north America.



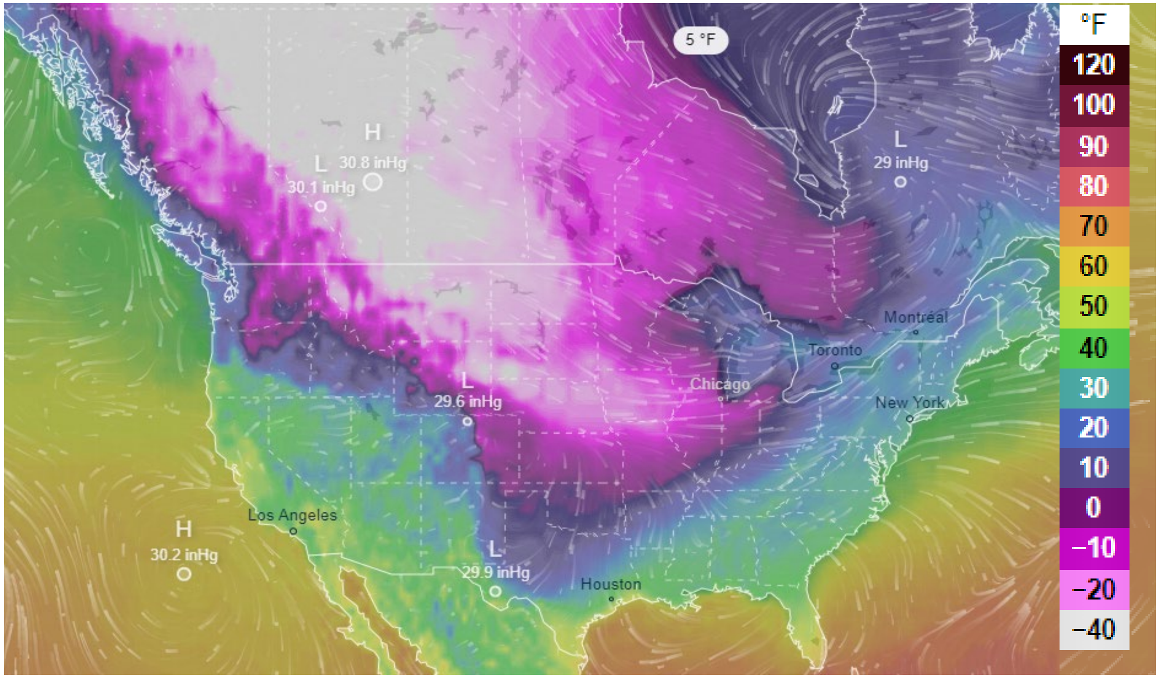
"Hot off the Press" Extreme Cold

- The BPS remained stable as persistent arctic cold covered much of North America. System operators-maintained reliability using their tools and procedures. Load Forecasting, and resources were managed throughout the event.



"Hot off the Press" Extreme Cold

- Registered entities dove into their operating procedures and tools declaring Energy Emergency Alerts, Conservative Operations, Cold Weather Advisories, Restricted Maintenance Operations, to mitigate the severe cold weather. There were no firm load shed events during this arctic cold weather system.



Questions and Answers